PARALLEL
PETROLEUM CORPORATION

P.E.
12-31-05

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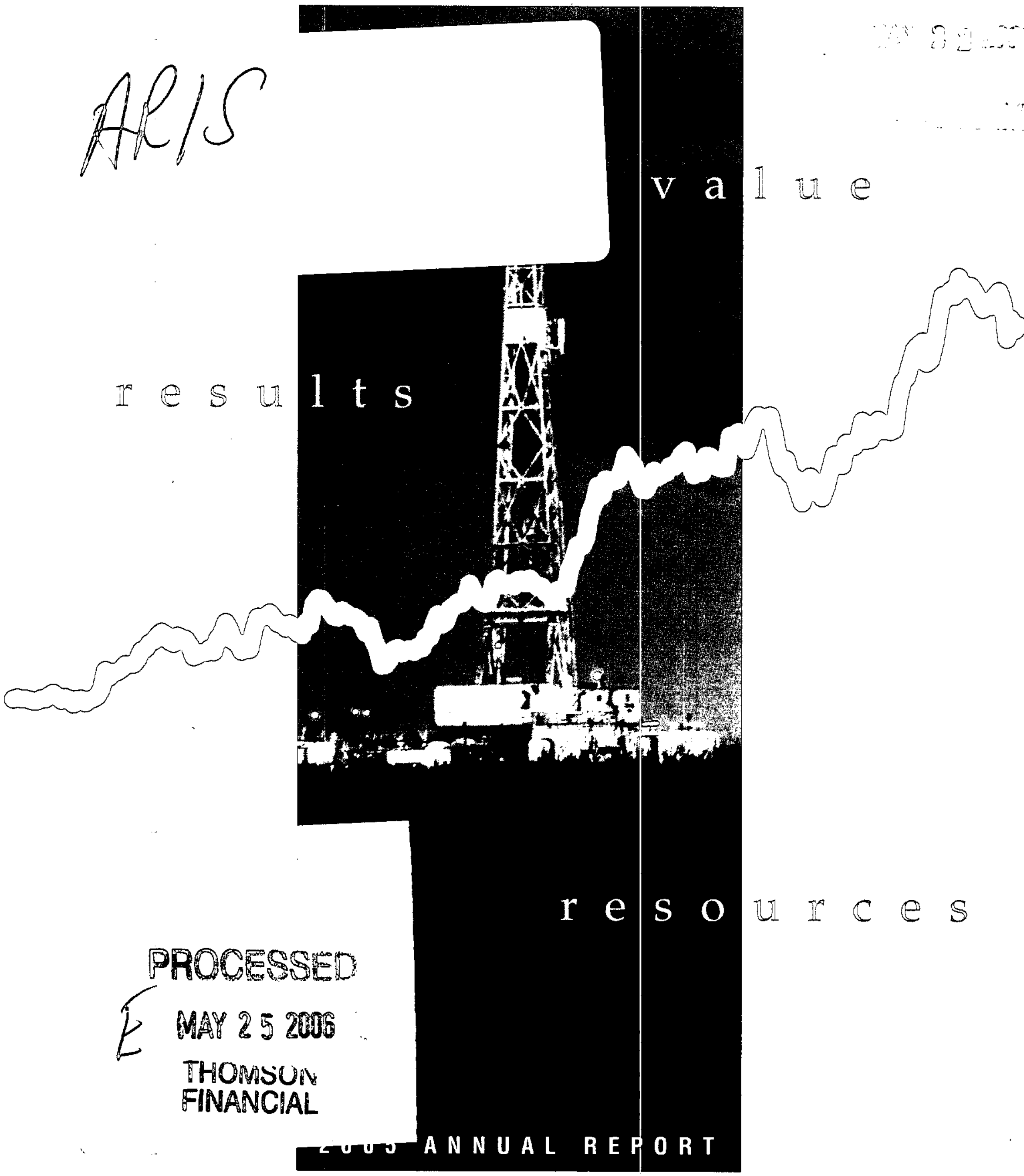

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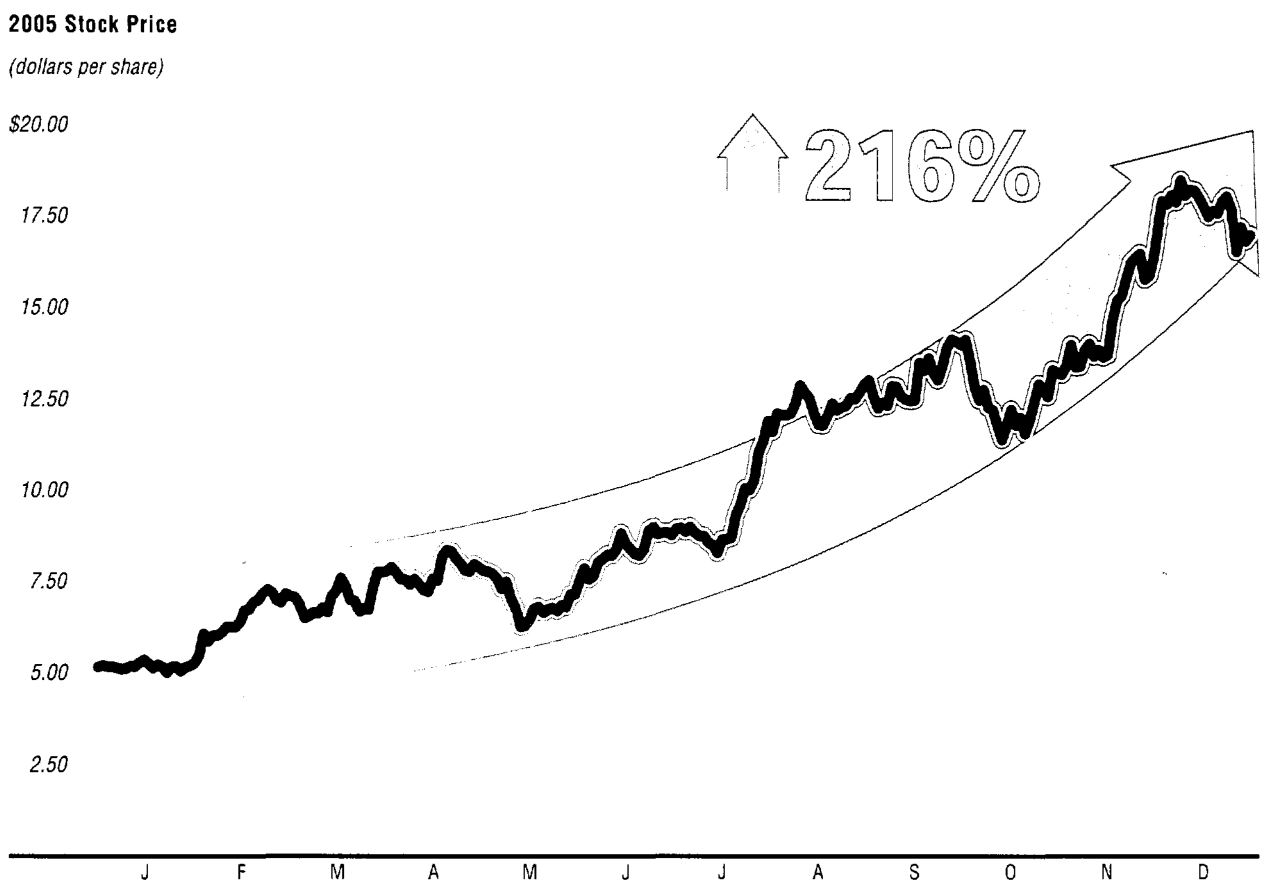
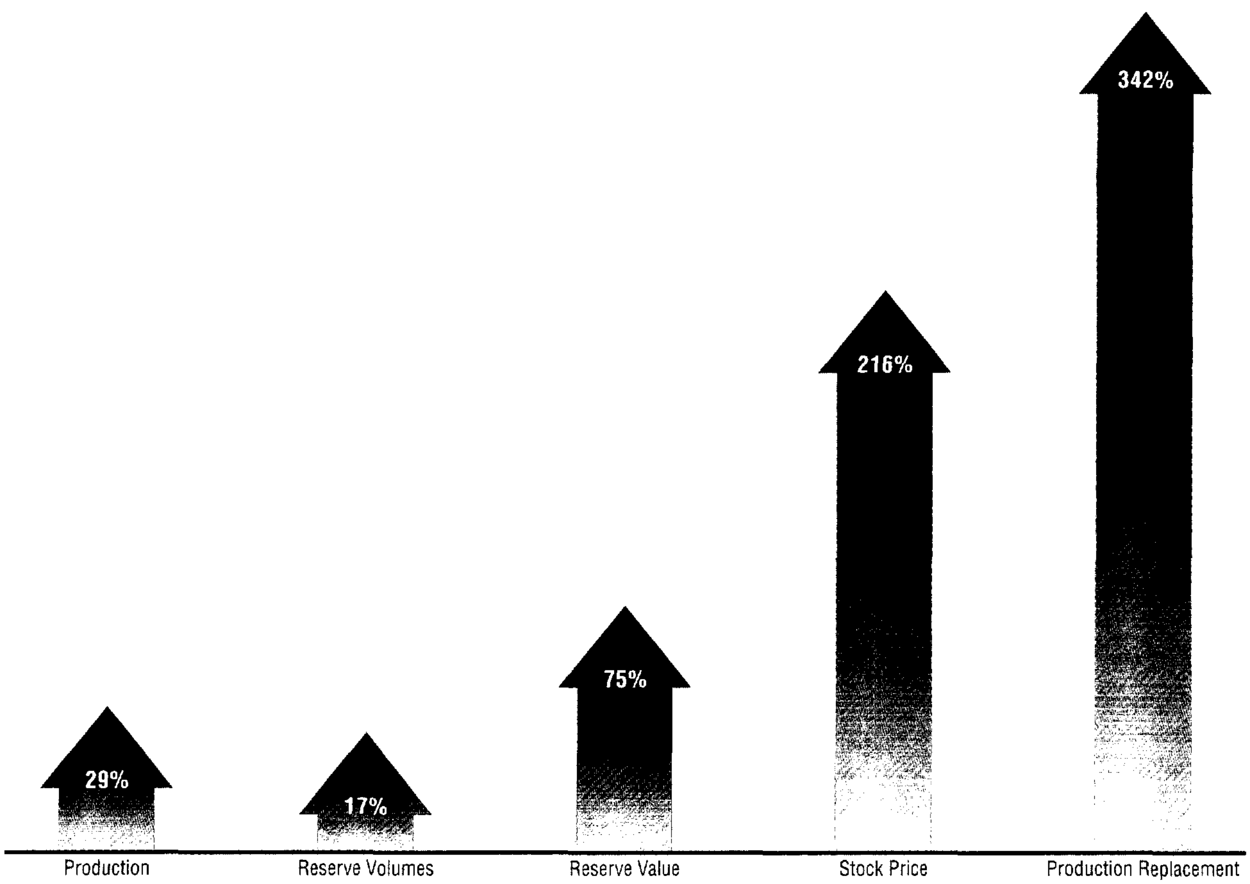


Parallel's stock price reached unprecedented new levels in 2005 as it increased over 200%

Strategy

Our primary objective is to increase the value of our common stock by increasing reserves, production, and net cash provided by operating activities. We attempt to reduce our financial risks by dedicating a smaller portion of our capital to high risk projects, while reserving the majority of our available capital for exploitation, development drilling and acquisition opportunities. Positions in long-lived oil and natural gas reserves are given priority over properties that might generate more net cash provided by operating activities in the early years of production, but which have shorter reserve lives.

One Year Results – 2005 Compared to 2004



Components of Our Strategy

Increase stockholder value by growth in reserves, production and net cash provided by operating activities

We have significantly grown our reserve base to 25.4 MMBOE from 3.2 MMBOE since the end of 2001, at an all-in cost of approximately $8.30 per BOE. As a result, we have significantly increased our production and net cash provided by operating activities.

Focus on longer lived oil and natural gas properties with consistent, shallow decline rates

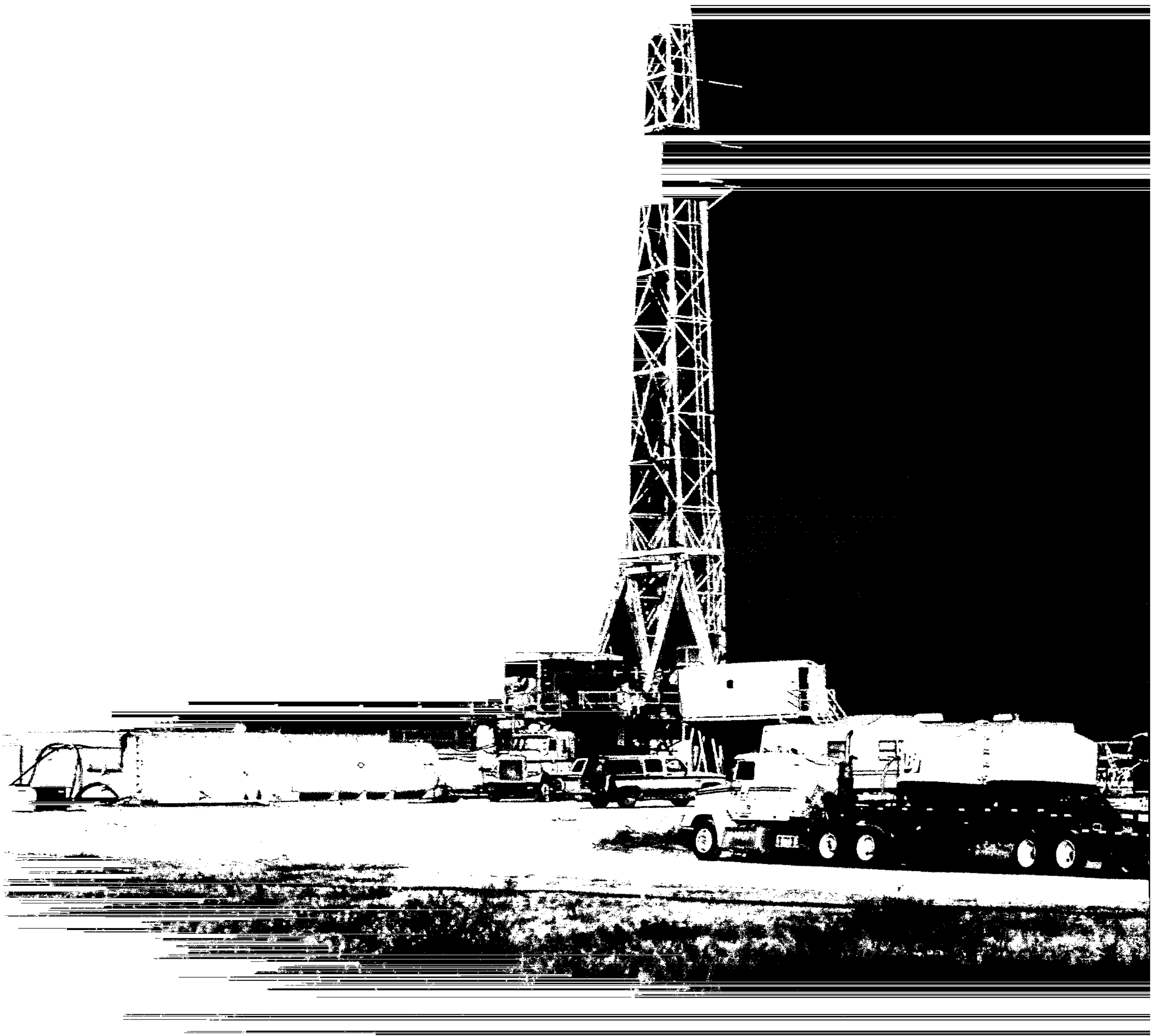
Since 2001, we have lengthened our reserve life index to 16.7 years from 4.7 years based on total proved reserves and to 10.8 years from 3.1 years based on proved developed reserves.

Expend the majority of our net cash provided by operating activities on lower risk projects

We continued to minimize our cost exposure in 2005 to higher risk projects by allocating less than 10% of our annual capital budget to exploratory drilling. Significant portions of our budget are dedicated to lower risk horizontal gas drilling and hydraulic fracture stimulations, recompletions, waterflood implementations, well deepenings and reactivations. As we have in the past, we will continue to use refracs and stimulations in our areas of operation. These are activities in which we have historically experienced a high degree of success.

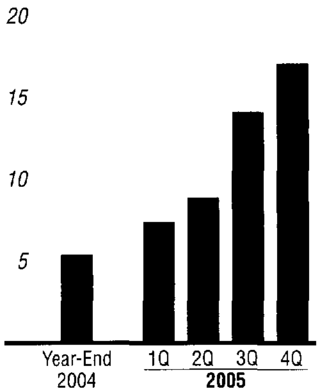
Complement our existing portfolio with core area acquisitions of underexploited assets

We focus our acquisition activities on properties with significant and low risk opportunities to efficiently increase production, as demonstrated by our success with our Fullerton, Diamond M, Carm-Ann/N. Means, and Harris property additions.

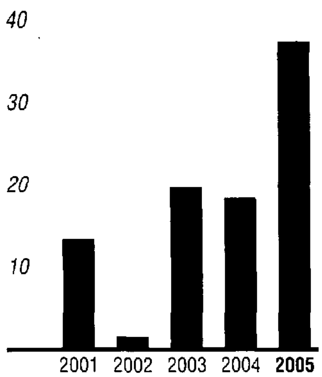


Fellow Stockholders:

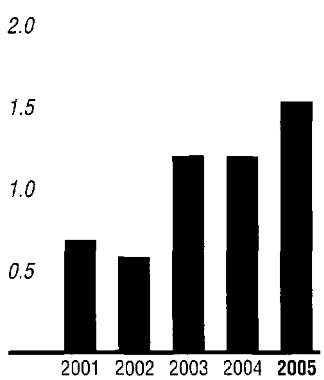
One-Year Stock Performance
(dollars per share)



Net Cash Provided by Operating Activities
(millions of dollars)



Production
(millions of BOE)



2005 was a record breaking year. Our team was highly effective in their precise execution of the new strategy adopted by Parallel in June 2002.

In 2002, we explained the steps we were going to implement to shift the focus of our company from "exploration" to "acquire and exploit." Management has steadfastly maintained a strong commitment to stay the course and execute our plan. In fact, we did exactly what we said we would do.

In 2002, we began acquiring and exploiting strategic assets and have continued to carry out our strategy each year. Our technical expertise and execution of the plan are two factors which have contributed to the increase of our stock price from $2.85 in June 2002 to $17.01 at the end of 2005, our highest stock price in the Company's twenty-six year history. After our common stock offering of 5.75 million shares on February 9, 2005 at $5.27 per share, the Company's stock price increased 223% at year end 2005.

When comparing 2005 to 2004, oil and gas revenues increased 85% to $66.1 million, net of $12.3 million of hedge payments, and net cash provided by operating activities increased 104% to $37.1 million, of which $14.0 million was realized in the fourth quarter. Production increased 29% to 1.52 million barrels of oil equivalent (BOE). This increase in production is the result of our 2005 capital investment in the development of our portfolio of projects.

We invested $77.4 million in our oil and gas acquisitions, exploitation and development in 2005, including $11.8 million that was invested in unproved property acquisition costs. Capital investments were funded with $37.1 million of net cash provided by operating activities, $28.0 million of proceeds from our common stock offering, and the balance through the utilization of our credit facilities.

During 2005, we added approximately 5.22 million BOE of new proved reserves for an approximate cost of $12.50 per BOE, excluding unproved property costs.

Our four-year, all-in, finding and development cost has been approximately $8.30 per BOE compared to the industry average of approximately $10 per BOE. The 5.22 million BOE of reserves added, compared to the 1.52 million BOE of reserves produced, represents a production replacement of 342%. Simply stated, we added 3.42 new BOE for each BOE produced in 2005.

Compared to 2004, the Company's proved reserves increased 17% to 25.4 million BOE. Of these proved reserves, 65% were proved developed, 83% were primarily oil, and 86% were operated by Parallel. The Company's Standardized Measure of Discounted Future Net Cash Flows increased 75% to $361 million. Our year-end 2005 price per barrel of oil increased 40% to $61.04, and the year-end 2005 price per million cubic feet (Mcf) of natural gas increased 53% to $9.43.

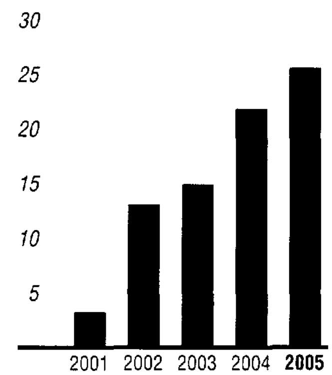
2006 Game Plan

Our 2006 game plan is primarily focused on our two resource gas projects: the New Mexico Wolfcamp and the North Texas Barnett Shale, which are in the early stages of development. Low-risk, long-life oil projects in the Permian Basin of West Texas are the cornerstone of our portfolio. The project portfolio will continue to be developed in 2006 by the same team of professionals who produced the outstanding results of 2005.

During 2006, we have budgeted approximately $103.7 million for capital investments, which does not include capital for the acquisition of producing properties. This is a $60.0 million increase over the Company's 2005 capital investment budget and will be funded out of our net cash provided by operating activities, which was $37.1 million in 2005, our $175.0 million credit facilities and non-strategic asset divestitures.

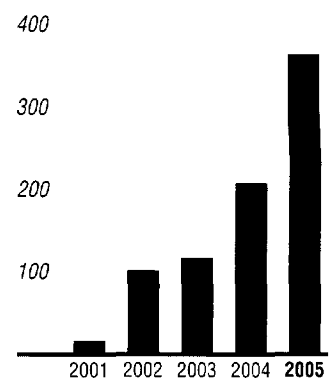
Proved Reserves

(millions of BOE)



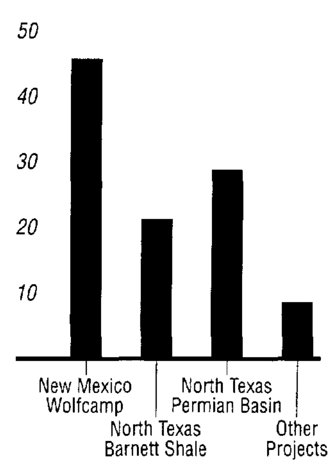
Standardized Measure of Discounted Future Net Cash Flows

(millions of dollars)



2006 Capital Budget

(millions of dollars)



Larry C. Oldham
President & CEO

Thomas R. Cambridge
Chairman

On a project basis, we expect to invest approximately $66.6 million, or 64%, of our $103.7 million 2006 capital investment budget in our New Mexico Wolfcamp and North Texas Barnett Shale gas projects. Of this $103.7 million, we have allocated $45.5 million to the New Mexico Wolfcamp, $21.1 million to the North Texas Barnett Shale, $28.6 million to the Permian Basin, and $8.5 million to our other projects.

On an operational expenditure basis, approximately $76.4 million, or 74%, of the 2006 capital investment budget is expected to be invested in the drilling and completion of an estimated 117 gross, or 66 net, wells. Approximately $4.4 million is expected to be invested in 30 gross, or 23 net, workovers, recompletions and lease equipment. Additionally, $12.6 million is designated for leasehold and 3-D seismic, $8.0 million for pipeline construction, and $2.3 million for lease maintenance and capitalized overhead.

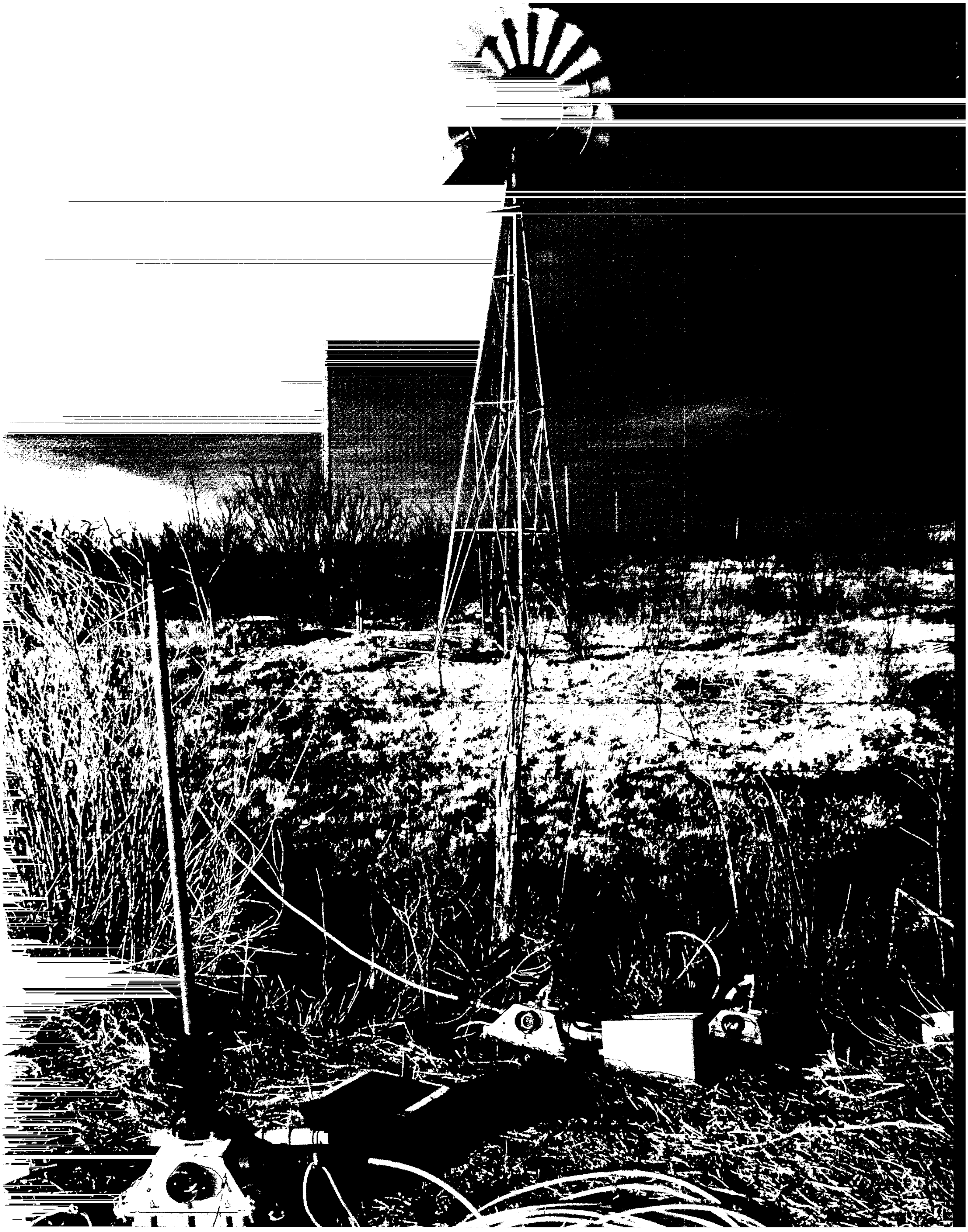
In 2006, we expect to achieve continued growth in reserve volumes, production, and operating margins, while maintaining a strong balance sheet. As we have stated since 2002, our primary goal is to increase the intrinsic value of our common stock. Based on early results, as discussed in our March 14, 2006 Operations Update press release, we expect another record-breaking year in 2006.

Sincerely,

Larry C. Oldham
President & CEO

Thomas R. Cambridge
Chairman

April 24, 2006



Financial Highlights

As described under "Financial Statement Restatement" beginning on Page 4 of the Form 10-K and as further disclosed in Note 18 on page 108 [F-29] in the notes to the consolidated financial statements, we restated our financial statements for the year ended December 31, 2004 and other financial information including quarterly information for the quarters ended September 30, June 30 and March 31 of 2005 and the quarters ended December 31 and September 30 of 2004.

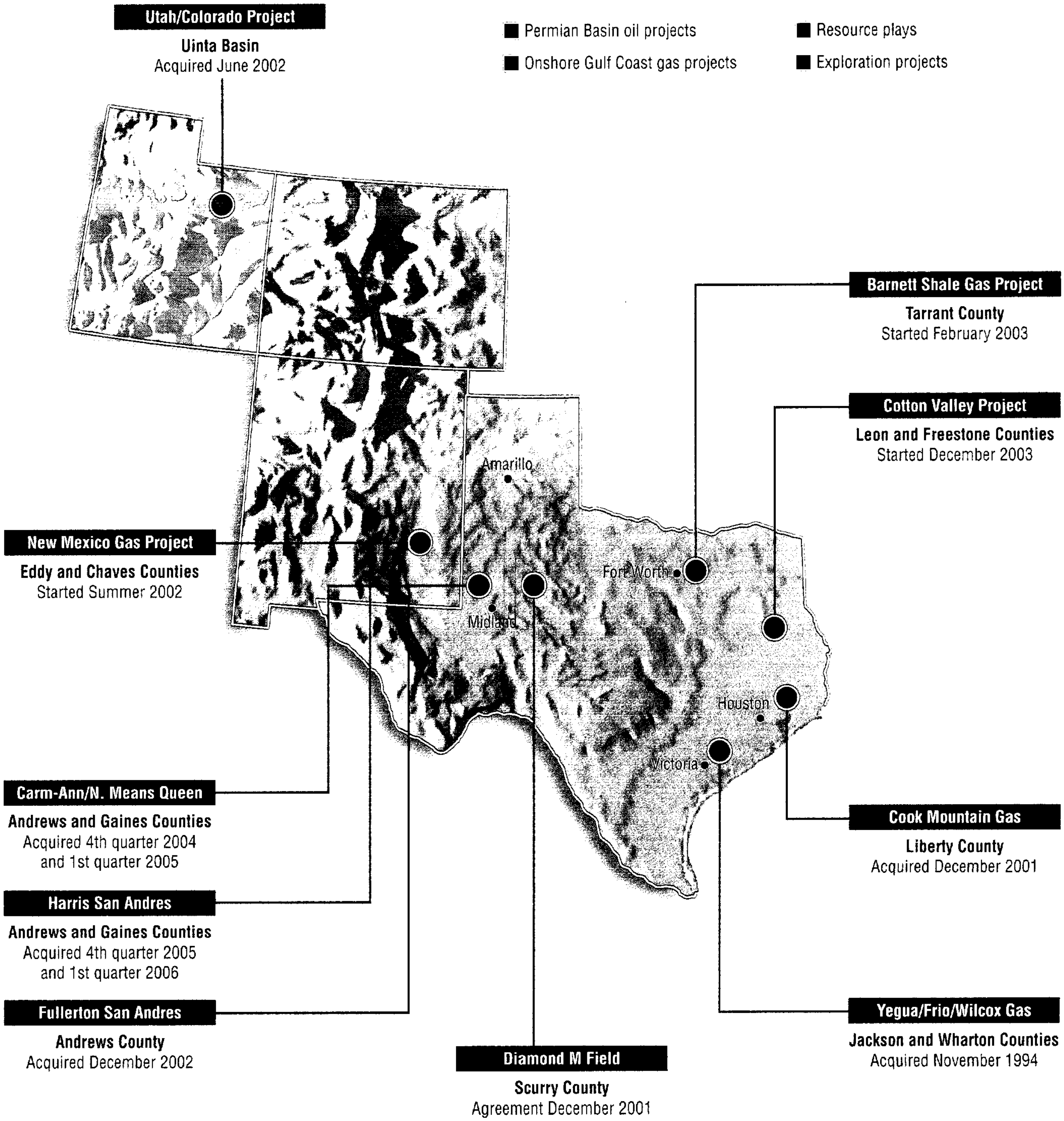
In the table below, we provide you with selected historical financial data. We have prepared this information using the audited consolidated financial statements for the five-year period ended December 31, 2005. It is important that you read this data along with our consolidated financial statements and related notes, and "Management's Discussion and Analysis of Financial Condition and Results of Operations" under Item 7 on page 37 of the Form 10-K. The selected financial data provided are not necessarily indicative of our future results of operations or financial performance.

Year ended December 31, (in thousands, except per share and per unit data)	**2005**	2004	2003	2002[(1)]	2001[(2)]
Consolidated Income Statements Data:		*(restated)*			
Operating revenues	**$ 66,150**	$ 35,837	$ 33,855	$ 12,106	$ 17,840
Operating expenses	**$ 33,085**	$ 23,571	$ 21,138	$ 11,250	$ 28,405
Income (loss) before cumulative effect of change in accounting principle	**$ (1,589)**	$ 2,271	$ 7,664	$ 18,701	$ (4,708)
Net income (loss)	**$ (1,589)**	$ 2,271	$ 7,602	$ 18,701	$ (4,708)
Cumulative preferred stock dividend	**$ (271)**	$ (572)	$ (580)	$ (585)	$ (585)
Net income (loss) available to common stockholders	**$ (1,860)**	$ 1,699	$ 7,022	$ 18,116	$ (5,292)
Net income (loss) per common share before cumulative effect of change in accounting principle					
Basic	**$ (0.06)**	$ 0.07	$ 0.33	$ 0.88	$ (0.26)
Diluted	**$ (0.06)**	$ 0.07	$ 0.31	$ 0.79	$ (0.26)
Weighted average common stock and common stock equivalents outstanding					
Basic	**32,253**	25,323	21,264	20,680	20,458
Diluted	**32,253**	25,688	24,175	23,549	20,458
Cash dividends – common stock	**$ —**	$ —	$ —	$ —	$ —
Consolidated Balance Sheet Data:					
Total assets	**$ 253,008**	$ 170,671	$ 118,343	$ 102,351	$ 41,760
Total liabilities	**$ 163,506**	$ 110,677	$ 57,111	$ 56,852	$ 15,446
Long-term debt, less current maturities	**$ 100,000**	$ 79,000	$ 39,750	$ 45,604	$ 9,600
Total stockholders' equity	**$ 89,502**	$ 59,994	$ 61,232	$ 45,499	$ 26,314
Consolidated Statement of Cash Flow Data:					
Cash provided by (used in)					
Operating activities	**$ 37,118**	$ 18,156	$ 19,493	$ 1,528	$ 13,383
Investing activities	**$ (84,949)**	$ (69,518)	$ (15,494)	$ (30,277)	$ (11,357)
Financing activities	**$ 49,468**	$ 38,765	$ 1,567	$ 37,210	$ (676)
Operating Data:					
Product Sales					
Oil (Bbls)	**923**	729	629	131	138
Gas (Mcf)	**3,592**	2,690	3,356	2,670	3,266
BOE	**1,522**	1,177	1,188	576	682
Average sales price					
Oil (per Bbl)	**$ 51.78**	$ 39.05	$ 29.11	$ 24.59	$ 24.80
Gas (per Mcf)	**$ 8.54**	$ 5.85	$ 5.40	$ 3.33	$ 4.41
Proved reserves					
Oil (Bbls)	**22,091**	18,916	12,084	10,271	916
Gas (Mcf)	**25,417**	16,825	16,271	15,633	13,947

(1) Results include a $31.0 million gain attributable to equit y in income of First Permian, L.P. Results also include noncash charges of $717,000 on the sale of stock we owned in Energen Corporation, $509,000 for the change in fair value of derivatives and $440,000 for the change in fair market value of our crude oil swaps.

(2) Results include noncash charges of $2.2 million in the fiscal quarter ended September 30, 2001 and $14.6 million in the fourth quarter ended December 31, 2001, in each case related to the impairment of oil and natural gas properties incurred in 2001 and primarily a result of a decrease in year-end reserves and lower oil and natural gas prices.

Areas of Operations

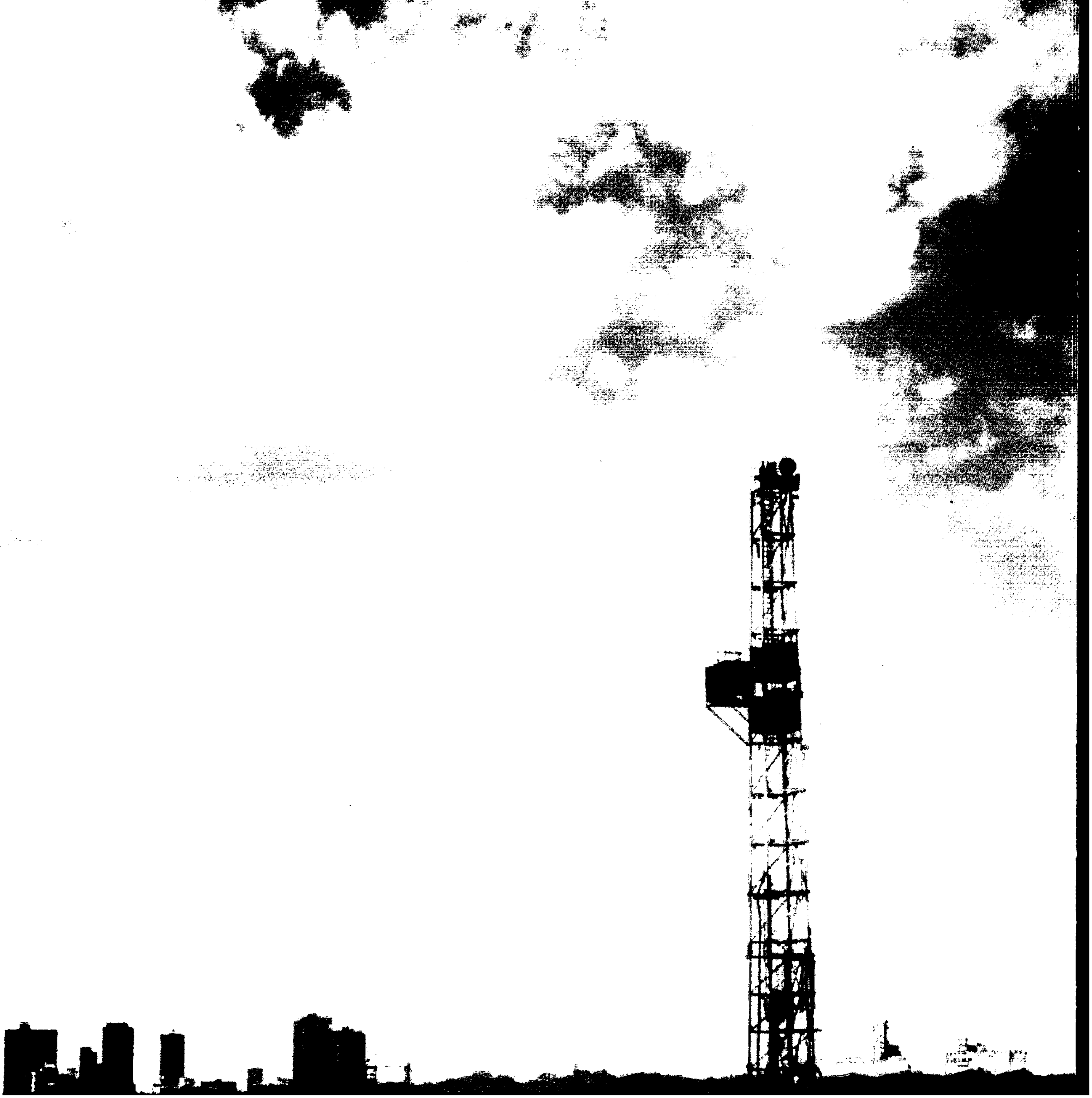


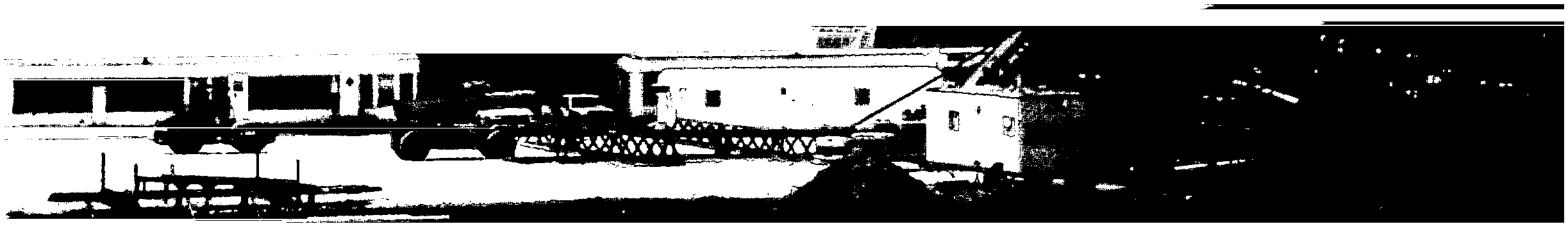
Our Oil and Natural Gas Properties

As indicated on the map to the left, we have a diverse portfolio of projects, including two resource gas plays in North Texas and New Mexico, four Permian Basin oil projects, two South Texas gas projects and two exploration projects. Our Barnett Shale resource gas play is located in the Forth Worth Basin of North Texas, and our Wolfcamp resource gas play is located in the Permian Basin of New Mexico. The Carm-Ann/N. Means, Harris, Diamond M, and Fullerton are Permian Basin projects located in West Texas and are primarily waterflood oil projects. Although we have de-emphasized our activity onshore the Gulf Coast of South Texas, we continue to have activity in our Yegua/Frio/ Wilcox and Cook Mountain gas projects. Finally, our current portfolio has two higher risk exploration drilling projects including the Utah/Colorado coal bed methane gas/ conventional oil and gas and East Texas Cotton Valley Reef projects. Each of our projects is described in the following pages.

Capital Investment Budget for 2006

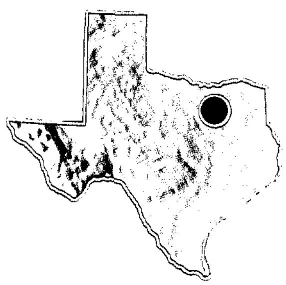
Our 2006 capital investment budget for properties we owned at March 1, 2006 is estimated to be approximately $103.7 million. On a geographic basis, approximately 20% of our projected 2006 capital investment program will be directed toward development of our North Texas Barnett Shale gas project, 44% for the Wolfcamp gas project in the Permian Basin of New Mexico, 28% will be directed toward oil and gas reserves in the Permian Basin of West Texas, 3% to gas reserves in the Onshore Gulf Coast area of South Texas and in East Texas, and the remaining 5% to other projects.





Resource Gas Projects

Parallel's two resource gas projects are in early stages of development. Our North Texas Barnett Shale and New Mexico Wolfcamp gas projects generated approximately 10% of our fourth quarter 2005 daily production, or 463 BOE per day, and represented approximately 5% of our reserve value as of December 31, 2005. We have budgeted approximately $66.6 million for these two resource gas projects in 2006 for the drilling and completion of 66 new wells, pipeline construction and leasehold acquisition.



9%

of our 4Q 05 daily production was realized in the North Texas Barnett Shale

4%

PROVED RESERVE VALUE at December 31, 2005

20%

2006 CAPEX

North Texas

Barnett Shale Gas Project

Tarrant County

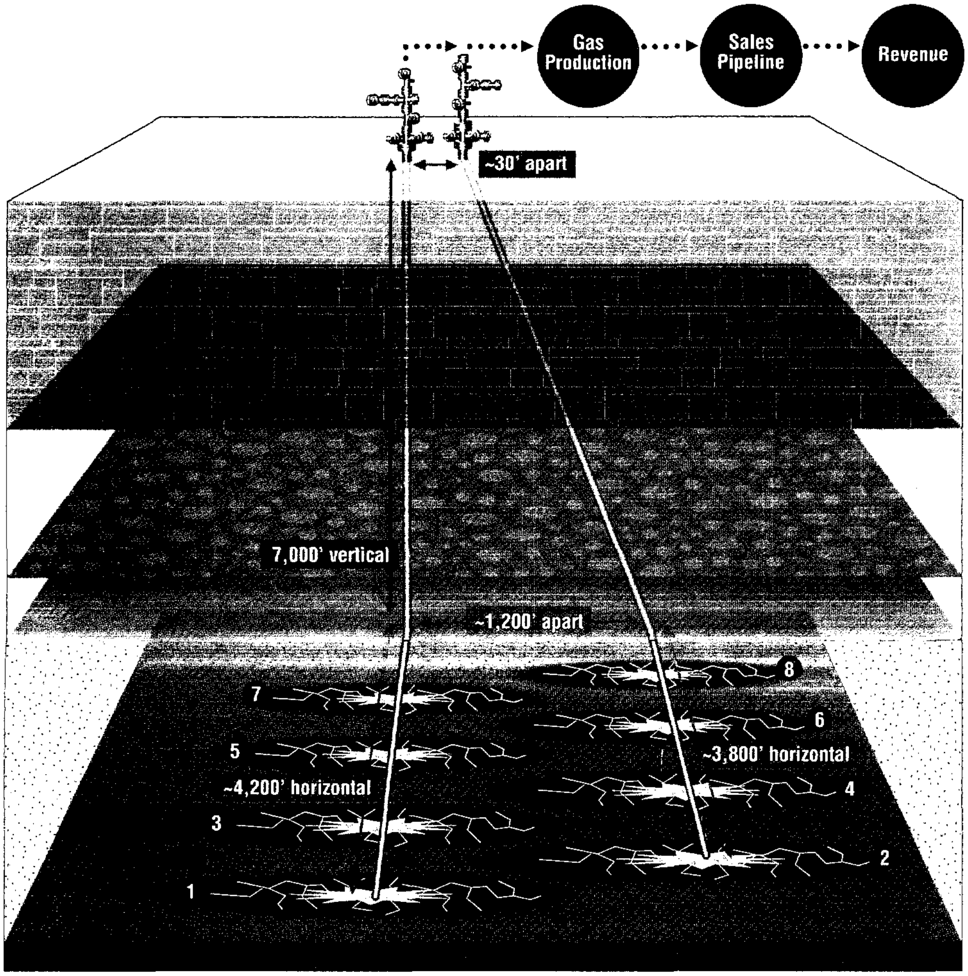
Non-Operated Property, 36.4% Base Working Interest

Our Barnett Shale gas project is located east of downtown Ft. Worth, in Tarrant County, Texas, between the Newark East Barnett Shale gas field to the north in Tarrant County and the Cleburne Barnett Shale gas field to the south in Johnson County. Our current leasehold position in the project is approximately 11,500 gross (4,200 net) acres. Our base working interest in the project is approximately 36.4%.

Our development of the Barnett Shale gas project began in the first quarter of 2005, accelerated in the third quarter, and is now in full swing. By March 14, 2006, our Barnett Shale gas project had 7 wells on production. The 7 wells were producing at a combined rate of approximately 24,000 gross Mcf of gas per day, or 3,994 gross BOE per day, which is 1,156 net BOE per day, including 240 net BOE per day associated with Parallel's recent acquisition of an additional 8.4% working interest in the project. The average daily producing rate from each of these 7 wells, as of March 14, 2006, ranged from a low of 1,000 gross Mcf to a high of 9,350 gross Mcf of gas per day.

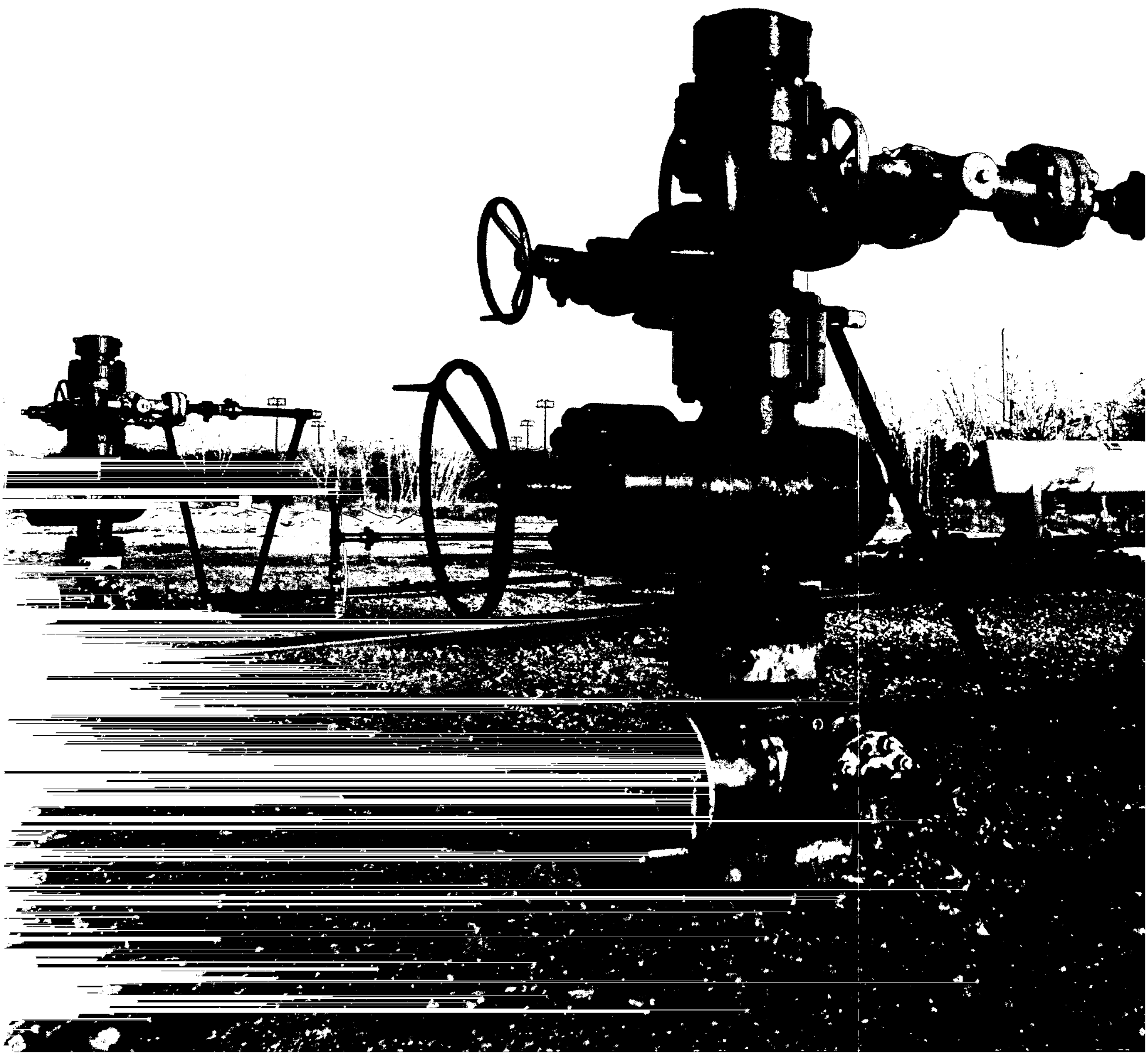
At March 14, 2006, this project had 9 other wells in various stages of pre-production operations. We estimate that it currently takes less than 30 days to drill and case a Barnett Shale well and have it ready to be frac'd into sales. The Company budgeted approximately $21.1 million for the project in 2006 for the drilling and completion of 18 new wells, pipeline construction and leasehold acquisition, which does not include the increased 2006 capital expenditures that resulted from the additional interests acquired in this project late in the first quarter of 2006.

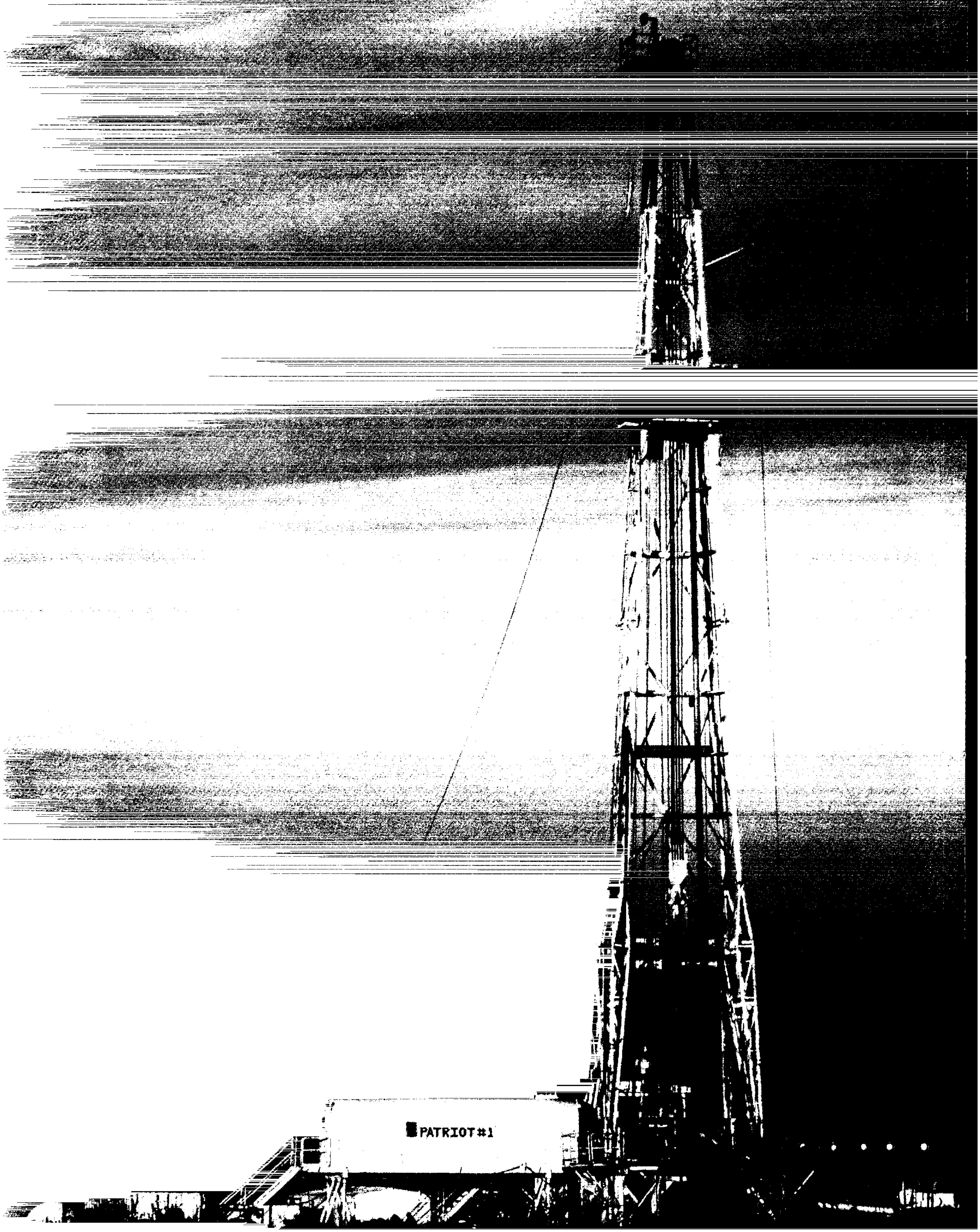
Well Fracture Technology



Our Team continues to tweak the hydraulic fracture completion technology in our Barnett Shale horizontal gas project. We have determined that there is a direct relationship between the length of the lateral and the initial production rates of the wells. Basically, longer laterals provide for more frac stages, which result in increased initial producing rates. We have also learned that situating the laterals of two adjacent wells parallel to each other allows for simultaneous, sequential fracture stimulations of the wells. We recently drilled two adjacent wells with horizontal laterals of approximately 4,000 feet in length, with the laterals situated approximately 1,200 feet apart and running parallel to each other. These two adjacent wells were fracture stimulated simultaneously, each sequentially, with a total of four frac stages per well, as shown in the illustration above. The results of these first two wells completed with this method of fracture stimulation were very encouraging. They began producing at initial rates of approximately 9,000 and 6,000 Mcf of gas per day, or approximately 590 BOE per day net to Parallel. We continue to explore opportunities to minimize costs and improve performance on this early-stage project.

Right: Barnett Shale gas wells that are only 30 feet apart on the surface can be completed with simultaneously frac'd horizontal sections that are hundreds of feet apart below the surface, as depicted in the illustration above.




PATRIOT #1

1%

of our 4Q 05 daily production was realized in the New Mexico Wolfcamp

1%

PROVED RESERVE VALUE at December 31, 2005

44%

2006 CAPEX

Permian Basin of New Mexico

Wolfcamp Gas Project

Eddy and Chaves Counties

Our Wolfcamp gas project is located in Eddy and Chaves counties in the Permian Basin of New Mexico. The project consists of three areas of mutual interest (AMI's) in which the primary target is the Wolfcamp formation at a depth of approximately 5,000 feet. As of March 14, 2006, Parallel's leasehold position in the project was approximately 149,000 gross (44,000 net) acres, combined, in Areas 1, 2 and 3.

Activity in the Wolfcamp gas project continues to accelerate. Techniques and procedures utilized in the project will continue to be refined, based on available information derived from each of the three areas. Based upon the results thus far, we believe this project has the potential to become a multi-well, long-life gas project that will be developed over the next three to five years. Initially, wells are being drilled on 320-acre spacing. As discussed below, 4 of our non-operated wells have now been drilled and completed on 160-acre spacing. After sufficient performance data has been evaluated, we anticipate that down-spacing may prove to be a viable option, and we are orienting our initial development to accommodate future 160-acre down-spacing.

As of March 14, 2006, we had participated in a total of 25 horizontal wells in our Wolfcamp gas project. Four were operated wells in Areas 2 and 3, and 21 were non-operated wells in Area 1. Twelve of the 25 wells were flowing to sales, 4 wells were being completed, 5 wells were awaiting completion, 1 workover was in progress, and 3 wells were drilling. The 12 producing wells are located in Area 1 and were flowing to sales at a combined rate of approximately 10,400 gross Mcf of gas per day, or 1,733 gross BOE per day, which is 200 BOE per day net to Parallel.

We anticipate participating in the drilling of approximately 48 horizontal wells in our New Mexico Wolfcamp gas project during 2006. We will operate twenty-four of the wells in Areas 2 and 3, and twenty-four wells in Area 1 will be non-operated. We budgeted approximately $45.5 million for the project in 2006 to fund the drilling and related leasing and infrastructure activity.

New Mexico Wolfcamp Gas Project - Area 1

Non-Operated AMI, 8.5% Base Working Interest

Area 1 of our Wolfcamp gas project consists of approximately 63,000 gross (4,600 net) acres. Parallel's base working interest in this non-operated AMI is approximately 8.5%.

In the first quarter of 2006, two non-operated wells were drilled in Area 1 as 160-acre offsets to two initial wells that were drilled in 2005. The two offset wells flowed at a combined initial rate of approximately 4,950 gross Mcf of gas per day, or 820 BOE per day, which is 77 BOE per day net to Parallel. The average initial test rate from each of the 2 initial and 2 offset wells ranged from a low of 1,450 gross Mcf to a high of 4,980 gross Mcf of gas per day.

Left: The Patriot #1 drilling rig is at work in our New Mexico Wolfcamp gas project. We plan to drill 48 horizontal wells in the project in 2006.

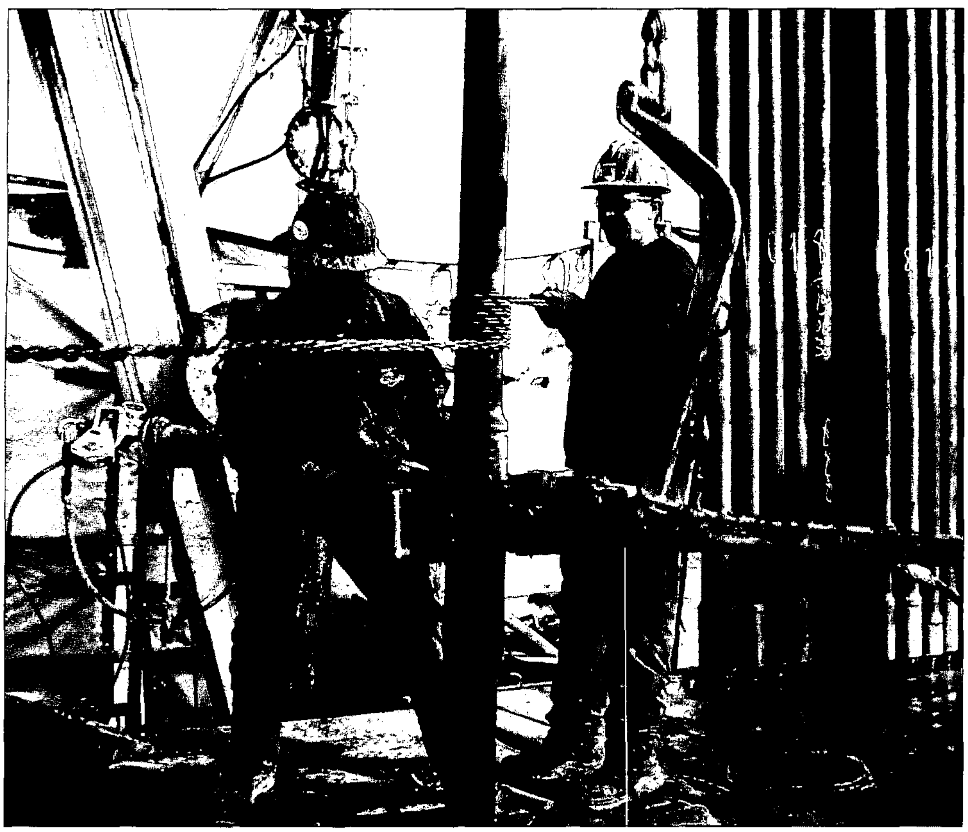
As of March 14, 2006, one other well was flowing at an initial rate of approximately 1,750 gross Mcf of gas per day, or 292 BOE per day, which is 48 BOE per day net to Parallel. Two wells had been tested at initial rates of 2,600 and 3,051 gross Mcf of gas per day, respectively, or 942 gross BOE per day, combined, which is 64 BOE per day net to Parallel. Both wells were shut-in awaiting pipeline connection. At March 14, 2006, we had 7 more wells underway in the area, of which 3 were being completed, 2 were awaiting completion, and 2 were drilling.

New Mexico Wolfcamp Gas Project – Area 2

Operated AMI, 85.0% Base Working Interest

Area 2 is contiguous to Area 1, is operated by Parallel, and consists of approximately 77,000 gross (35,000 net) acres. Our base working interest in this operated AMI is approximately 85.0%.

We initiated well operations on the Seabiscuit No. 1 vertical well in the second quarter of 2005 with the re-entry of a plugged and abandoned well to determine the economic viability of properly stimulated vertical wells and to collect basic data for utilization in horizontal well design. At March 14, 2006, this well was still shut-in awaiting pipeline connection. Our first two horizontal wells in this area, the Affirmed No. 1H and the Seabiscuit No. 2H, were awaiting completion, and the third well, the Dash For Cash No. 1H, was drilling. We were also in the process of preparing to install our own treating plant and pipeline to gather, process and transport gas in Area 2.



Left: A drilling crew adds a joint of drill pipe to a well as it is drilled in our New Mexico Wolfcamp gas project.

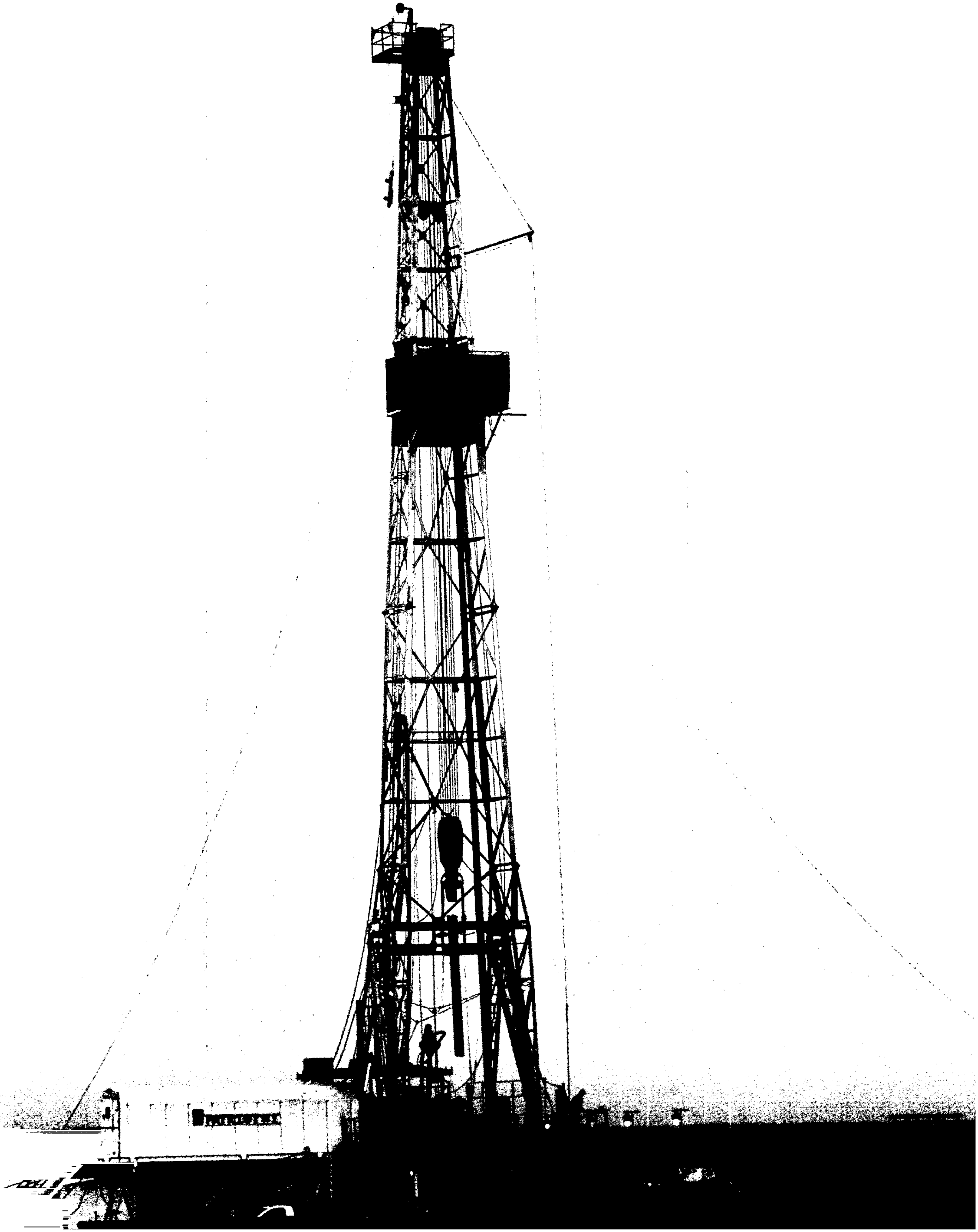
New Mexico Wolfcamp Gas Project – Area 3

Operated AMI, 85.0% Base Working Interest

Area 3 is located within the original confines of Area 1 and is operated by Parallel. We have been actively increasing our leasehold position in this area, which consisted of approximately 9,000 gross (5,000 net) acres at March 14, 2006. Our base working interest in this operated AMI is approximately 85.0%.

Our first horizontal well in Area 3 had been drilled and was awaiting completion as of March 14, 2006. We expect services to become available for completion of this well during the second quarter of 2006. We own an approximate 50% working interest in this operated well.

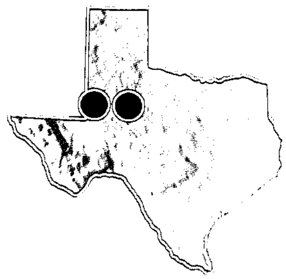
Right: Work continues around the clock in our accelerated New Mexico Wolfcamp gas project.



Permian Basin of West Texas

Our projects in the Permian Basin of West Texas are in close proximity to our Midland, Texas headquarters and are primarily waterflood oil projects. These projects generated approximately 59% of our fourth quarter 2005 daily production, or 2,914 BOE per day, and represented approximately 85% of our reserve value as of December 31, 2005. Our 2006 capital investment budget designates $28.6 million for the drilling and completion of 44 new wells, 30 workovers, equipment, pipeline construction, seismic and leasehold acquisition in our Permian Basin projects.

Carm-Ann San Andres Field/N. Means Queen Unit
Andrews & Gaines Counties, Texas
Operated Property, 77.0% Working Interest
The acquisition of this property, which occurred in late 2004 and early 2005, established a new core operating area that is located within 50 miles of our headquarters. Initial development of these properties began in March 2005 with the drilling of 16 in-fill San Andres wells and one Queen well. The success of the 2005 drilling program prompted us to budget additional activity for 2006 and to acquire the adjacent Harris field, which is discussed on page 21. The Carm-Ann/N. Means properties generated approximately 11% of the Company's fourth quarter 2005 daily production, or 554 BOE per day, and represented approximately 13% of our reserve value as of December 31, 2005.



59%

of our 4Q 05 daily production was realized in the Permian Basin of West Texas

85%

PROVED RESERVE VALUE at December 31, 2005

28%

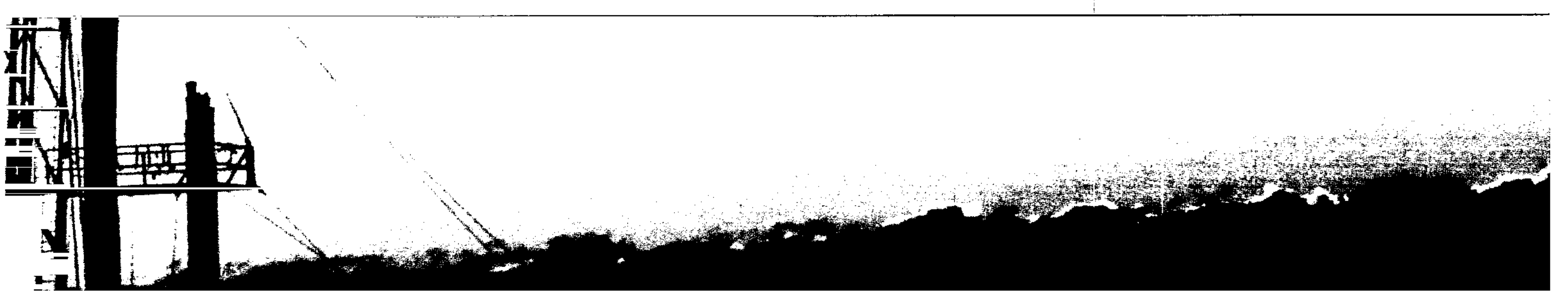
2006 CAPEX

The $5.0 million budgeted to the Carm-Ann/N. Means project in 2006 is earmarked for the drilling and completion of 11 new wells and the workover of 9 existing wells. All 11 of the new wells will be situated on injection well locations and will be converted from oil producers to water injection service at the appropriate time. The 2006 drilling activity in Parallel's Carm-Ann field began on December 28, 2005. As of March 14, 2006, the Company had drilled eight wells, averaging approximately eight days from spud to rig release on each well. Four of the new wells had been completed and were on pump testing at an estimated combined rate of 320 gross BOE per day, or 190 BOE per day net to Parallel. The other 4 new wells were awaiting completion. Drilling was underway on the ninth well. Two wells remained to be drilled to complete the 11-well drilling package. Parallel is the operator of this property with an average working interest of approximately 77%.

Harris San Andres
Andrews & Gaines Counties, Texas
Operated Property, 90.0% Working Interest

In the fourth quarter 2005 and first quarter 2006, we acquired the Harris San Andres properties. The project includes approximately 6,100 gross (5,490 net) acres, is approximately one mile from our Carm-Ann assets, and will be integrated into our Carm-Ann base of operations.

This recently acquired project generated approximately 1% of the Company's fourth quarter 2005 daily production, or 55 BOE per day, and represented approximately 8% of its reserve value as of December 31, 2005. At March 14, 2006, net production from this project was approximately 400 BOE per day, including the additional interest acquired on January 12, 2006. We budgeted approximately $11.1 million for the Harris San Andres project in 2006 for the drilling of 23 wells and 4 workovers. Parallel is the operator of these properties with an average working interest of approximately 90%.



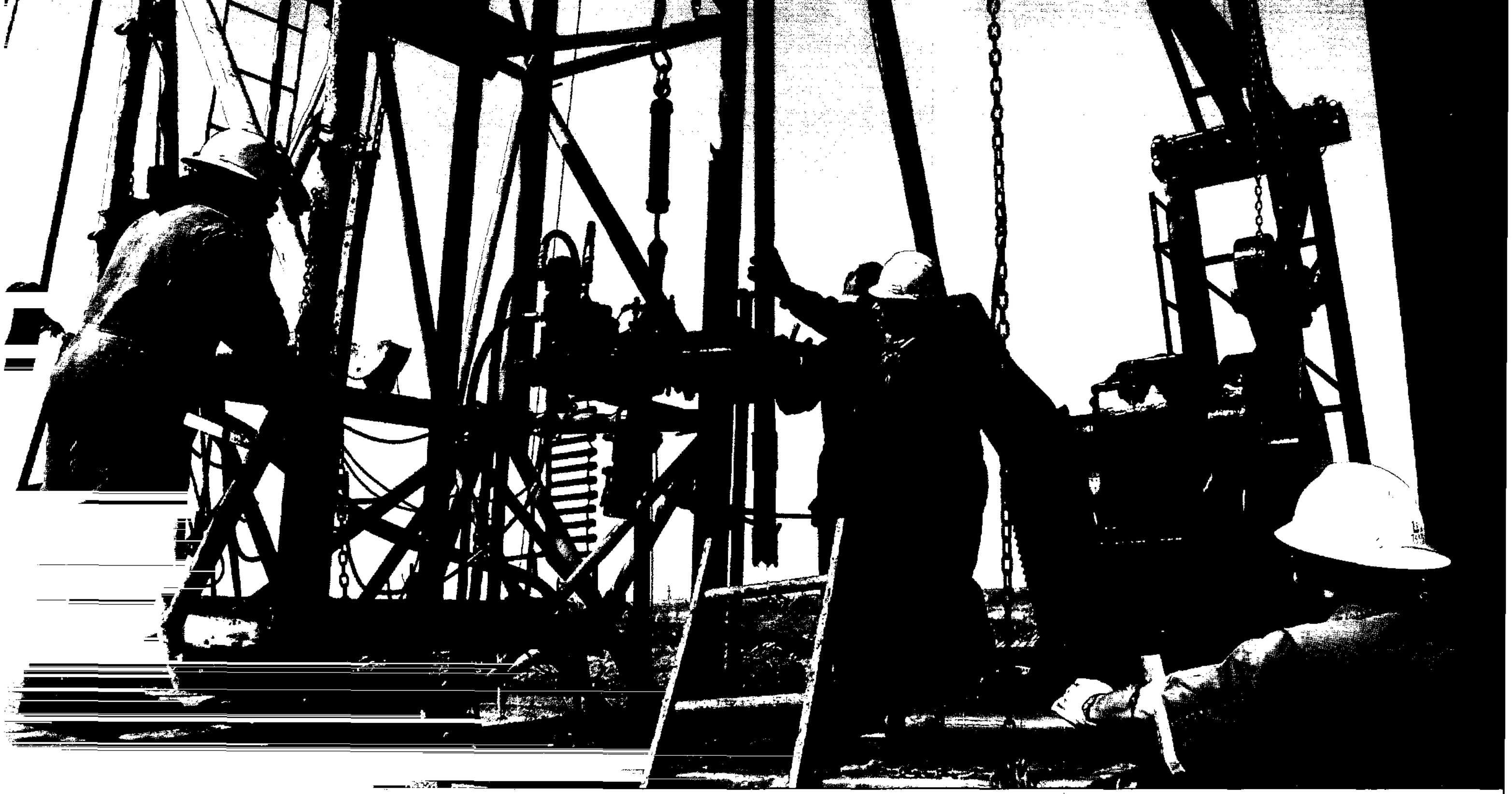
Diamond M Canyon Reef Unit
Scurry County, Texas

Operated Property, 66.0% Working Interest

The Diamond M Canyon Reef Unit consists of approximately 5,800 gross (3,800 net) acres. The Canyon Reef interval ranges in depth from 4,000 feet to 6,950 feet. The Unit is located between the SACROC Unit to the north and east and the Sharon Ridge Unit to the south. The SACROC and Sharon Ridge Units were both discovered in 1948 and have produced in excess of 1.3 billion barrels of oil and 250 million barrels of oil, respectively. The Diamond M Canyon Reef Unit was also discovered in 1948 but was historically a neglected property and is, therefore, immature in comparison to the SACROC and Sharon Ridge Units. This is the highest potential oil target in our portfolio of projects.

The Diamond M Canyon Reef project generated approximately 7% of our fourth quarter 2005 daily production, or 339 BOE per day, and represented approximately 9% of our reserve value as of December 31, 2005. 2006 activity in our Diamond M Canyon Reef project has revolved primarily around the acquisition of a new 3-D seismic survey. The survey is somewhat unique in that it will acquire both pressure-wave (P-wave) and shear-wave (S-wave) data, and we anticipate that it will provide more detail and better compartmental imaging than a "typical" 3-D seismic survey. By March 14, 2006, the P-wave acquisition was complete, and the S-wave acquisition had begun.

We have budgeted approximately $8.3 million for the project in 2006 for the acquisition of the new 3-D seismic survey, the drilling of 6 new wells, and the continuation of the deepening program with 12 additional workovers. Parallel is the operator of these properties with an average working interest of approximately 66% above the contractual base volumes associated with the Company's work-to-earn arrangement with Southwestern Energy Company (NYSE: SWN). As of March 14, 2006, we had drilled the first 2 of the six new wells budgeted for the year. One well was on pump at an initial test rate of 300 gross barrels of oil per day, or 171 BOE per day net to Parallel. Completion operations were in progress on the second well. We anticipate that the remaining four new wells will be drilled later in the year, after processing and interpretation of the 3-D seismic survey is completed.



Above: A drilling crew completes a well in our Diamond M project.

Diamond M Shallow Leases
Scurry County, Texas
Operated Property, 66.0% Working Interest
The Diamond M Shallow is comprised of eight shallow leases located within the confines of the larger Canyon Unit. These leases comprise approximately 1,740 gross (1,150 net) acres in the Glorieta, Clearfork and Wichita Albany intervals, which range in depth from 2,450 feet to 4,000 feet. The Diamond M Shallow property generated approximately 1% of the Company's fourth quarter 2005 daily production, or 66 BOE per day, and represented approximately 10% of its reserve value as of December 31, 2005.

During 2004, we drilled 12 producing well locations and 18 water injection well locations in the project. It is our practice to produce the injection well locations for a period of time to condition the formation for injection and to improve economic return. All but two of the 18 wells were converted to injection service during 2005. As of March 14, 2006, we were monitoring flood response. We will resume development, once satisfactory response is observed. We budgeted approximately $200,000 for the project in 2006 for general maintenance and workovers, pending waterflood response. Parallel is the operator of these properties with an average working interest of approximately 66% above the contractual base volumes associated with the Company's work-to-earn arrangement with Southwestern Energy Company.

Fullerton San Andres Field
Andrews County, Texas
Operated Property, 82.0% Working Interest
Our Fullerton properties are situated on nine contiguous leases containing approximately 3,640 gross (3,150 net) acres and produce from the San Andres formation at a depth of 4,400 feet. These properties were initially acquired in December 2002 and additional interests were acquired in 2004. Development of this property through the end of 2005 primarily consisted of the re-stimulation of approximately 80 existing producing wells and the drilling of 19 new producing wells. We budgeted approximately $1.8 million for the Fullerton project in 2006 for the drilling and completion of 4 new wells and 5 workovers. As of March 14, 2006, this year's activity had consisted primarily of the re-fracture stimulation of 6 active producing wells, with 3 additional similar workovers were scheduled. Since we acquired it in late 2002, this project has generated the largest daily production volumes in our portfolio. It is a legacy asset that will be a long-term contributor to our net cash provided by operating activities.

This property generated approximately 33% of our fourth quarter 2005 daily production, or 1,588 BOE per day, and represented approximately 39% of our reserve value as of December 31, 2005. Parallel owns an 82% average working interest in these properties.

Other Permian Basin Projects
Various Texas Counties
Operated and Non-Operated Properties, Varying Working Interests
We have a number of properties located in the Permian Basin of West Texas which have been a part of our portfolio for many years. These properties generated approximately 6% of our fourth quarter 2005 daily production, or 312 BOE per day, and represented approximately 6% of our reserve value as of December 31, 2005. We budgeted approximately $2.2 million for Other Permian Basin properties in 2006, primarily for lease and well equipment, well maintenance and capitalized overhead.

One of these properties, the Page E No. 6, was recently re-stimulated. The re-stimulation, which was performed at a cost of approximately $42,500, has returned a temporarily abandoned well to producing status. As of March 14, 2006, the gross initial rate of the well was approximately 285 Mcf of gas per day, or 48 BOE per day, which is 38 BOE per day net to Parallel. At that test rate, we estimate that the well will increase total lease production 55%, from just over 500 Mcf of gas per day to approximately 800 Mcf of gas per day, and payout will occur in less than two months. Parallel is the operator of the property with a 100% working interest.

Right: A rig is at work in the drilling of the fifth Wilcox well in our South Texas gas project.

31%

of our 4Q 05 daily production was realized in the Onshore Gulf Coast

10%
PROVED RESERVE VALUE at December 31, 2005

3%
2006 CAPEX

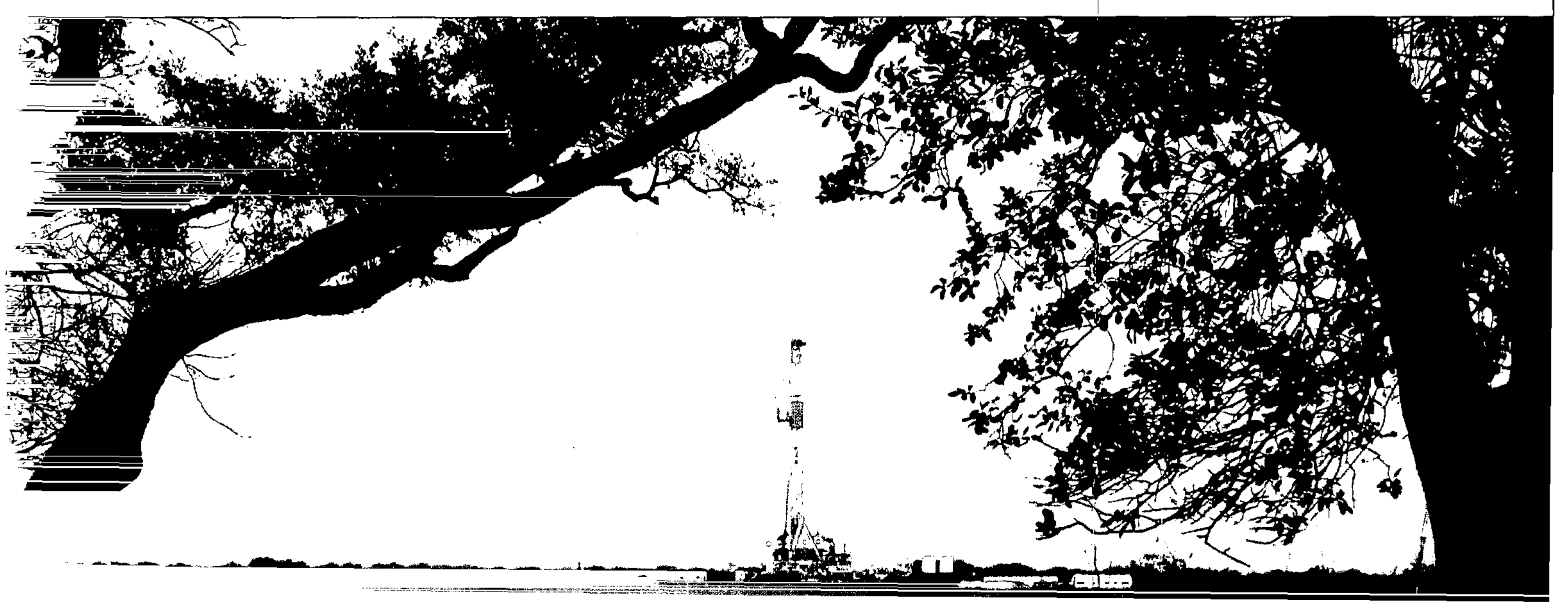
Onshore Gulf Coast of South Texas

Yegua/Frio/Wilcox and Cook Mountain Gas Projects
Jackson, Wharton and Liberty Counties
Non-Operated Properties, Varying Working Interests

From 1993 to June 2002, the Onshore Gulf Coast of South Texas was our primary focus. However, because of the high decline rate and short-lived reserves, we began decreasing our investment in this area. We changed our business strategy in June 2002 and started re-deploying a majority of the net cash provided from operations in this area to the acquisition, development and exploitation of longer life oil and gas reserves. On our "way out the door", we drilled a successful Wilcox discovery. Primarily due to our Wilcox wells, the Onshore Gulf Coast of South Texas generated approximately 31% of our fourth quarter 2005 daily production, or 1,496 BOE per day, and represented approximately 10% of our reserve value as of December 31, 2005.

As of March 14, 2006, our fifth Wilcox well had been completed and was selling gas at the rate of approximately 9,000 gross Mcf of gas per day and 150 gross barrels of oil per day, or 1,650 gross BOE per day, which is 193 BOE per day net to Parallel. The 5 Wilcox gas wells were producing at a combined rate of approximately 34,600 gross Mcf of gas per day and 570 gross barrels of oil per day, or 6,337 gross BOE per day, which was 819 BOE per day net to Parallel. At March 14, 2006, the average daily producing rate from each of these five wells ranged from a low of 3,000 gross Mcf to a high of 10,000 gross Mcf of gas per day. Parallel's working interest in this project is approximately 15.9% before payout and approximately 23.8% after payout.

The Company budgeted approximately $2.8 million for the South Texas projects in 2006 for the drilling and completion of 1 Wilcox well and 4 Yegua/Frio/Cook Mountain wells. At March 14, 2006, a new Cook Mountain well had been completed. We plan to drill 2 deep Frio wells during the second quarter of 2006.



East Texas

Cotton Valley Reef Gas Project
Leon and Freestone Counties
Non-Operated Property, 13.125% Working Interest
The East Texas Cotton Valley Reef is a 3-D seismic gas project that has a higher risk profile than the Company's other projects. The objective is the Cotton Valley barrier reef facies found between depths of approximately 16,000 and 18,000 feet. The project consists of approximately 5,000 gross (650 net) acres. This project contributes minimally to the Company's current daily production and reserve value.

We budgeted approximately $1.5 million for the Cotton Valley Reef gas project in 2006 for additional leasehold and 1 well that is expected to start drilling during the second quarter of 2006. Parallel owns an approximate 13.125% working interest in this project.

Utah/Colorado

CBM (Coal Bed Methane) Gas/Conventional Oil & Gas Projects
Uinta Basin
Operated Property, 100% Working Interest
We own and operate 100% of our Utah/Colorado project and have increased our leasehold acreage position to approximately 160,000 net acres. This is a multiple zone project consisting of both oil and gas targets at depths of less than 6,000 feet. The Utah/Colorado project does not yet contribute to our daily production or reserve value. We continue to evaluate seismic and geologic data.

We budgeted approximately $4.2 million for this project in 2006 for the drilling and completion of 1 well and the acquisitions of a 3-D seismic survey and additional leasehold. Our first test well, the Sunshine Bench No. 2, was drilled based on historical 2-D seismic and geologic information. The well spudded on February 18, 2006, was drilled to a total depth of approximately 5,200 feet, open-hole logged, selectively side-wall cored, and plugged and abandoned. The well information will be incorporated into the 3-D seismic survey that is currently in progress. One additional well has been permitted.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

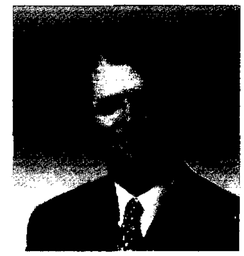
Executive Officers and Directors

Larry C. Oldham

Donald E. Tiffin

Steven D. Foster

Eric A. Bayley



John S. Rutherford

Thomas R. Cambridge

Dewayne E. Chitwood

Martin B. Oring

Ray M. Poage

Jeffrey G. Shrader

Executive Officers

Larry C. Oldham
President and CEO

Donald E. Tiffin, PE
Chief Operating Officer

Steven D. Foster, CPA
Chief Financial Officer

Eric A. Bayley, PE
Vice President of Corporate Engineering

John S. Rutherford, CPL
Vice President of Land and Administration

Board of Directors

Thomas R. Cambridge, Chairman
President, Cambridge Production, Inc.,
an oil and gas exploration and production company

Larry C. Oldham
President and CEO, Parallel Petroleum Corporation

Dewayne E. Chitwood
President and CEO, Wes-Tex Holdings, LLC,
an oil and gas exploration and production company

Martin B. Oring
Managing Member, Wealth Preservation, LLC,
a financial counseling firm

Ray M. Poage
Retired Partner, KPMG LLP

Jeffrey G. Shrader
Attorney, Sprouse Shrader Smith P.C.

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

[X] Annual Report Pursuant to Section 13 or 15 (d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2005

[ ] Transition Report Pursuant to Section 13 of 15(d) of the Securities Exchange Act of 1934

For the transition period from ______ to ______

Commission File Number: 0 - 13305

Parallel Petroleum Corporation

(Exact Name of Registrant as Specified in its Charter)

Delaware	75-1971716
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1004 N. Big Spring, Suite 400 Midland, Texas	79701
(Address of Principal Executive Offices	(Zip Code)

Registrant's Telephone Number, Including Area Code: (432) 684-3727

Securities Registered Pursuant to Section 12(b) of the Act: None

Securities Registered Pursuant to Section 12(g) of the Act:

Common Stock, $.01 par value
Common Stock Purchase Warrants
Rights to Purchase Series A Preferred Stock
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes [ ] No [✓]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes [ ] No [✓]

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [✓] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [✓]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer [ ] Accelerated Filer [✓] Non-Accelerated Filer [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [✓]

The aggregate market value of voting and non-voting common equity held by non-affiliates of the Registrant as of March 14, 2006 was approximately $520.5 million, based on the closing price of the common stock on the same date.

At March 14, 2006 there were 34,856,416 shares of common stock outstanding.

FORM 10-K

TABLE OF CONTENTS

Cautionary Statement Regarding Forward Looking Statements

Some statements contained in this Annual Report on Form 10-K are "forward-looking statements." These forward looking statements relate to, among others, the following:

- our future financial and operating performance and results;
- our business strategy;
- market prices;
- sources of funds necessary to conduct operations and complete acquisitions;
- development costs;
- number and location of planned wells;
- our future commodity price risk management activities; and
- our plans and forecasts.

We have based these forward-looking statements on our current assumptions, expectations and projections about future events.

We use the words "may", "will", "expect", "anticipate," "estimate", "believe", "continue", "intend", "plan", "budget", "future", or "reserves" and other similar words to identify forward-looking statements. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations. We believe the assumptions and expectations reflected in these forward-looking statements are reasonable. However, we cannot give any assurance that our expectations will prove to be correct or that we will be able to take any actions that are presently planned. All of these statements involve assumptions of future events and risks and uncertainties. Risks and uncertainties associated with forward-looking statements include, but are not limited to:

- fluctuations in prices of oil and natural gas;
- demand for oil and natural gas;
- losses due to potential or future litigation;
- future capital requirements and availability of financing;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- competition;
- general economic conditions;
- governmental regulations;
- receipt of amounts owed to us by purchasers of our production and counterparties to our derivative contracts;
- decisions to either enter into derivative contracts or not;
- events similar to 911;
- actions of third party co-owners of interests in properties in which we also own an interest;
- fluctuations in interest rates;
- weaknesses in our internal controls; and
- the inherent variability in early production tests.

For these and other reasons, actual results may differ materially from those projected or implied. We believe it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. We caution you against putting undue reliance on forward-looking statements or projecting any future results based on such statements.

Before you invest in our common stock, you should be aware that there are various risks associated with an investment. We have described some of these risks in other sections of this Annual Report on Form 10-K and under Item 1a Risk Factors, beginning on page 21.

Financial Statement Restatement

Overview

As announced in our Current Report on Form 8-K filed with the Securities and Exchange Commission on March 14, 2006, we identified certain derivative transactions that were accounted for improperly. Accordingly, this Annual Report on Form 10-K for the year ended December 31, 2005 includes detailed disclosures relative to the restatement of our consolidated financial statements for the year 2004, the third and fourth fiscal quarters in 2004, and the first three fiscal quarters of 2005 to correct the errors in accounting for derivative transactions during those periods as identified by us. We did not identify any such errors in periods prior to June 30, 2004.

This restatement had the following effect on net income (loss) in the applicable periods:

	Year Ended	Quarter Ended		
(dollars in thousands)	December 31, 2004	March 31, 2005	June 30, 2005	September 30, 2005
Net income (loss) as previously reported	$ 5,585	$ (550)	$ 1,453	$ 8,587
Adjustments to net income	(3,314)	(10,154)	(2,699)	(6,598)
Restated net income (loss)	$ 2,271	$ (10,704)	$ (1,246)	$ 1,989

The restatement had the following effect on the consolidated statement of cash flows for the nine months ended September 30, 2005.

	As previously reported	Adjustment	As Restated
Net cash provided by operating activities	$ 19,112	$ 4,022	$ 23,134
Net cash used in investing activities	$ (34,680)	$ (4,022)	$ (38,702)

We have not amended and do not intend to amend our previously filed Annual Reports on Form 10-K or our Quarterly Reports on Form 10-Q for the periods affected by the restatement that ended prior to March 31, 2005. For this reason, the consolidated financial statements, reports of our independent registered public accounting firm and related financial information for the affected periods contained in any other reports on periods prior to March 31, 2005 should no longer be relied upon. In light of the restatement, readers should no longer rely on our audited financial statements and other information for the fiscal year December 31, 2004 and our unaudited financial statements and other information for the quarters ended September 30 and December 31, 2004, and the quarters ended March 31, June 30, and September 30, 2005 (including management's evaluation of internal controls, and disclosure controls and procedures).

History of the Derivatives Issue

As a part of the preparation of our financial statements for the year ended December 31, 2005, we undertook a review of our accounting for oil and gas and interest rate derivatives. We use derivative instruments as a means of reducing financial exposure to fluctuating oil and gas prices and interest rates. We included changes from period to period in the fair value of derivatives classified as cash flow hedges ("Hedges") as increases and decreases to Accumulated Other Comprehensive Income ("AOCI") as allowed by Statement of Financial Accounting Standards No. 133, *"Accounting for Derivative Instruments and Hedging Activities"* ("FAS 133"). This Hedge accounting treatment is allowed for certain derivatives, including the types of derivatives used by us to reduce exposure to changes in oil and gas prices associated with the sale of oil and gas production and interest rates. In order to qualify for Hedge accounting treatment, specific standards and documentation requirements must be met. We believed that we met those requirements and that our derivative accounting treatment was permitted under FAS 133. However, after a review of the applicable derivative accounting rule, and our accounting policies and procedures related to our derivative hedging, management determined that certain of our derivatives did not qualify for Hedge accounting under FAS 133. Specifically, management determined that documentation of the relationship of hedged items and the derivative instruments being employed and designated as hedges was insufficient for derivative instruments entered into during periods subsequent to June 30, 2004, and that accounting for derivative instruments entered into during periods subsequent to June 30, 2004 as cash flow hedges was, therefore, inappropriate. Management of the Company reported its determination to the Audit Committee.

During the review and its determination, management reported its progress to the Audit Committee, BDO Seidman, LLP and to the Board of Directors. On the basis of its analysis and determination, management recommended to the Audit Committee and the Board of Directors on March 8, 2006 that previously reported financial results for the year ended December 31, 2004, the last two fiscal quarters of 2004, and the first three fiscal quarters of 2005 should be restated to reflect the correction of these errors. The Audit Committee agreed with this recommendation. Pursuant to the recommendation of the Audit Committee, the Board of Directors determined at its meeting on March 8, 2006 that our previously reported financial results be restated to correct the errors in the accounting for derivatives. In light of the restatement, the Board of Directors also determined that the financial statements and other information containing the errors should no longer be relied upon.

Effects of the Restatement

The following tables set forth the effects of the restatement relating to the derivatives transactions for which the accounting was determined to be in error. The periods affected by these errors were the year ended December 31, 2004, the quarters ended March 31, June 30 and September 30, 2005, and the quarters ended September 30 and December 31, 2004.

(in thousands)	Year Ended December 31, 2004
Income (expense) amounts:	
Disqualification of the use of hedge accounting for certain derivative transactions	$ (5,021)
Provision for income taxes	1,707
Net decrease in reported net income and net income available to common shareholders	$ (3,314)
Per share amounts:	
Basic, as previously reported	$ 0.20
Adjustment	(0.13)
Basic, as restated	$ 0.07
Diluted, as previously reported	$ 0.20
Adjustment	(0.13)
Diluted, as restated	$ 0.07

	Quarter Ended			
(in thousands)	March 31, 2005	June 30, 2005	September 30, 2005	Total
Income (expense) amounts:				
Disqualification of the use of hedge accounting for certain derivative transactions	$ (15,385)	$ (4,090)	$ (9,996)	$ (29,471)
Provision for income taxes	5,231	1,391	3,398	10,020
Net decrease in reported net income and net income available to common shareholders	$ (10,154)	$ (2,699)	$ (6,598)	$ (19,451)
Per share amounts:				
Basic, as previously reported	$ (0.02)	$ 0.04	$ 0.25	$ 0.27
Adjustment	(0.36)	(0.08)	(0.19)	(0.63)
Basic, as restated	$ (0.38)	$ (0.04)	$ 0.06	$ (0.36)
Diluted, as previously reported	$ (0.02)	$ 0.04	$ 0.25	$ 0.27
Adjustment	(0.36)	(0.08)	(0.19)	(0.63)
Diluted, as restated	$ (0.38)	$ (0.04)	$ 0.06	$ (0.36)

(in thousands)	Quarter Ended September 30, 2004	Quarter Ended December 31, 2004	Total
Income (expense) amounts:			
Disqualification of the use of hedge accounting for certain derivative transactions	$ (4,417)	$(604)	$ (5,021)
Provision for income taxes	1,502	205	1,707
Net decrease in reported net income and net income available to common shareholders	$ (2,915)	$(399)	$ (3,314)
Per share amounts:			
Basic, as previously reported	$ 0.04	$0.07	$ 0.11
Adjustment	(0.12)	(0.01)	(0.13)
Basic, as restated	$ (0.08)	$0.06	$ (0.02)
Diluted, as previously reported	$ 0.04	$0.07	$ 0.11
Adjustment	(0.12)	(0.02)	(0.14)
Diluted, as restated	$ (0.08)	$0.05	$ (0.03)

The restatement had the following effect on the consolidated statement of cash flows for the nine months ended September 30, 2005.

	As previously reported	Adjustment	As Restated
Net cash provided by operating activities	$ 19,112	$ 4,022	$ 23,134
Net cash used in investing activities	$ (34,680)	$ (4,022)	$ (38,702)

Amended and restated financial and other information can be found in the following sections of this Annual Report on Form 10-K:

Item 6

Item 7

Item 8 – See Note 18 to the consolidated financial statements

Item 9A

PART I

Item 1. Business

About Our Company

Parallel Petroleum Corporation, or "Parallel" and its subsidiaries are engaged in the acquisition, development and exploitation of long life oil and natural gas reserves and, to a lesser extent, the exploration for new oil and natural gas reserves. The majority of our current producing properties are in the:

- Permian Basin of west Texas and New Mexico;
- Fort Worth Basin of north Texas; and
- The onshore gulf coast area of south Texas.

In addition, we are actively evaluating, leasing, drilling and preparing to drill on two other projects located in the Cotton Valley Reef trend of east Texas and the Uinta Basin of Utah.

In 2005, we spent approximately $77.4 million on oil and gas related capital expenditures, an increase of approximately 14% over that expended in 2004 (See Note 3 to the consolidated financial statements). This amount includes approximately $20.8 million of acquisition costs for the Harris San Andres properties we acquired in November 2005. In January 2006 we acquired additional interests in the Harris San Andres properties for a net purchase price of approximately $23.4 million.

Throughout this report, we refer to some terms that are commonly used and understood in the oil and gas industry. These terms are:

• Bbl or Bbls	barrel or barrels of oil or other liquid hydrocarbons;
• Bcf	billion cubic feet of natural gas;
• BOE	equivalent barrel of oil or 6 Mcf of natural gas for one barrel of oil;
• MBbls	thousand barrels of oil or other liquid hydrocarbons;
• MBoe	thousand barrels of oil equivalent;
• MMBbls	million barrels of oil or other liquid hydrocarbons;
• MMBoe	million barrels of oil equivalent;
• MMBtu	million British thermal units;
• Mcf	thousand cubic feet of natural gas; and
• MMcf	million cubic feet of natural gas.

Parallel was incorporated in Texas on November 26, 1979, and reincorporated in the State of Delaware on December 18, 1984.

Our executive offices are located at 1004 N. Big Spring, Suite 400, Midland, Texas 79701. Our telephone number is (432) 684-3727.

Available Information

You may read and copy any materials we file with, or furnish to, the Securities and Exchange Commission at the SEC's public reference facilities at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the public reference facilities by calling the SEC at 1-800-SEC-0330. The SEC maintains a website (http://www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, including Parallel, that file electronically with the SEC.

Our website address is http://www.plll.com. Information on our website or any other website is not incorporated by reference into this Annual Report on Form 10-K and does not constitute a part of this Annual Report on Form 10-K.

We make available free of charge on our Internet website our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

We will provide electronic or paper copies of our SEC filings free of charge upon request made to Cindy Thomason, Manager of Investor Relations, cindyt@plll.com, 1-800-299-3727.

Developments in 2005; 2006 Capital Budget

On February 9, 2005, we sold 5,750,000 shares of common stock, $.01 par value per share, in a public offering at a price of $5.27 per share. Gross proceeds were $30.3 million, and net proceeds were approximately $27.7 million. The common shares were issued under our $100.0 million universal shelf registration statement on Form S-3 which became effective in November 2004.

On May 4, 2005, we called for the redemption of all 950,000 outstanding shares of our privately held 6% Convertible Preferred Stock. As permitted under the terms of the preferred stock, all of the holders of the preferred stock elected to convert their shares of preferred stock into shares of Parallel's common stock based on the conversion rate of $10.00 divided by $3.50. Therefore, the holders of the preferred stock received approximately 2.8571 shares of common stock of Parallel for each share of preferred stock, together with cash payable with respect to fractional shares and accumulated and unpaid dividends up to the conversion date. Dividends on the preferred stock ceased to accrue, and the preferred stock is no longer outstanding from and after June 6, 2005, the date on which all of the preferred stock was converted.

In November 2005 and January 2006, we effected a series of oil and gas property acquisitions in Andrews and Gaines Counties, Texas for an aggregate net purchase price of approximately $44.2 million. Cawley Gillespie & Associates, Inc., our independent petroleum engineers, estimated that these recently acquired properties (excluding the properties acquired after December 31, 2005) contain aggregate proved reserves of approximately 6.4 MMBoe.

Our 2006 capital investment budget for properties we owned at March 1, 2006 is estimated to be approximately $103.7 million, which includes $12.6 million for the purchase of leasehold and seismic in our areas of activity. The budget will be funded from our estimated operating cash flows and bank borrowings. The amount and timing of our expenditures are subject to change based upon market conditions, results of expenditures, new opportunities and other factors.

Proved Reserves as of December 31, 2005

Cawley Gillespie & Associates, Inc., our independent petroleum engineers, estimated the total proved reserves attributable to all of our oil and gas properties to be 21.2 MMBbls of oil and 25.2 Bcf of natural gas as of December 31, 2005.

Approximately 83% of our proved reserves are oil and approximately 65% are categorized as proved developed reserves.

About Our Strategy and Business

From 1993 until mid 2002, our activities were concentrated in the onshore gulf coast area of south Texas. In June, 2002 we reexamined and revised our business strategy. We shifted the balance of our investments from properties having high rates of production in early years to properties with more consistent production over a longer term. We now emphasize reducing drilling risks by dedicating a smaller portion of our capital to high risk projects, while reserving the majority of our available capital for acquisition, exploitation, enhancement and development drilling opportunities. Obtaining positions in long-lived oil and natural gas reserves is given priority over properties that might provide more cash flow in the early years of production, but which have shorter reserve lives. Our risk reduction efforts also include emphasizing acquisition possibilities over high risk exploration projects.

Since the latter part of 2002, we have reduced the emphasis on high risk exploration efforts and we now focus on established geologic trends where we can utilize the engineering, operational, financial and technical expertise of our entire staff. Although we will continue to participate in exploratory drilling activities from time to time, reducing financial, reservoir, drilling and geological risks and diversifying our property portfolio are the principal criteria in the execution of our business plan.

In summary, our current business plan:

- focuses on projects having less geological risk;
- emphasizes acquisition, exploitation, development and enhancement activities;
- includes the utilization of horizontal and fracture stimulation technologies on certain types of reservoirs;
- focuses on acquiring producing properties; and
- expands the scope of our operations by diversifying our exploratory and development efforts, both in and outside of our current areas of operation.

An integral part of our business strategy includes exploitation and enhancement activities. Exploitation and enhancement activities include:

- operational enhancements, such as surface facility reconfiguration, and the installation of new or additional compression equipment;
- workovers;
- well recompletions;
- behind-pipe recompletions;
- refracing (restimulating a producing formation within an existing wellbore to enhance production and add reserves);
- installation of injection wells and related facilities;
- development well drilling (infill drilling);
- cost reduction programs; and
- secondary recovery operations, including waterfloods.

When we initiate exploitation and enhancement activities on our existing producing properties, we first establish and maintain an ongoing program of oil and gas well reviews with the objective of maximizing the output of existing wells. Oil and gas wells usually generate their highest volumes during the earlier stages of production after which production begins to decline. Enhancement and remedial work can be undertaken to restore varying amounts of lost production or reduce the rate of production decline.

Our approach to producing property acquisitions, and the size and timing of any acquisition, is dependent upon market conditions in the domestic oil and gas industry. Generally, during periods of moderate to high prices for oil and gas, we believe that oil and gas acquisition opportunities are not as favorable to a prospective purchaser as they are when market conditions are depressed.

Producing properties that we identify and attempt to acquire will include properties that have proved undeveloped and behind-pipe reserves, operational enhancement potential, long-lived reserves, multiple pay-zone exploitation and development drilling opportunities, and the potential for operating control. We believe that selecting and acquiring producing properties having these characteristics will diversify and improve the quality of our property portfolio.

Although purchases of producing properties involve less risk than drilling, there is a risk that estimates of future prices or costs, reserves, production rates or other criteria upon which we have based our investment decision may prove to be inaccurate.

In addition to acquisitions of producing properties, our business strategy also includes seeking opportunities to negotiate and enter into "work to earn", joint venture and similar agreements with third parties for development operations on producing properties.

Our sources for possible acquisitions of leases and prospects include independent landmen, independent oil and gas operators, geologists and engineers. We also evaluate properties that become available for purchase. If our review of an undeveloped lease or prospect or a producing property indicates that it may have geological characteristics favorable for 3-D seismic analysis, we may decide to acquire a working interest in the property or an option to acquire a working interest. In the case of producing properties, we also seek properties that we believe are underperforming relative to their potential. To reduce our financial exposure in any one prospect, we may enter into co-ownership arrangements with third parties. These arrangements are common in the industry and enable us to participate in more prospects and share the drilling and related costs and dry-hole risks with other participants. From time to time, we sell prospects to third parties or farm-out prospects and retain an interest in revenues from these prospects.

As we have in the past, we continue to:

(1) Use Advanced Technologies – We believe the use of 3-D seismic surveys, horizontal drilling, fracture stimulation and other advanced technologies provides us with a risk management tool. We believe that our use of these technologies in exploring for, developing and exploiting oil and gas properties can:

- reduce drilling risks;
- lower finding costs;
- provide for more efficient production of oil and natural gas from our properties; and
- increase the probability of locating and producing reserves that might not otherwise be discovered.

Generally, 3-D seismic surveys provide more accurate and comprehensive information to evaluate drilling prospects than conventional 2-D seismic technology. We evaluate substantially all of our exploratory prospects using 3-D seismic technology. On some exploratory prospects, we also use amplitude versus offset, or AVO analysis. AVO analysis shows the high contrast between sands and shales and assists in determining the presence of natural gas in potential reservoir sands.

We believe that using 3-D seismic, AVO and other technologies gives us a competitive advantage because of the increased likelihood of successful drilling. When we evaluate exploratory prospects in geographical areas where the use of 3-D and other advanced technologies are not likely to provide any advantages, we use traditional evaluation methods, such as 2-D seismic technology.

(2) Serve as Geophysical Operator – We prefer to serve as the geophysical operator on projects located in areas where we have experience using 3-D seismic technology. By doing so, we control the design, acquisition, processing and interpretation of 3-D surveys and, in most cases, determine drilling locations and well depths. The integrity of 3-D seismic analysis in our projects is enhanced by emphasizing quality controls throughout the data acquisition, processing and interpretation phases.

We retain experienced outside consultants and participate with knowledgeable joint working interest owners when we acquire, process and interpret 3-D seismic surveys. When possible, we also attempt to correlate or model the interpretations of 3-D seismic surveys with wells previously drilled on or near the prospect being evaluated.

(3) Conduct Exploratory Activities – Although we do not intend to emphasize exploratory drilling to the extent we have in the past, when we do undertake exploratory projects, we will continue to focus on prospects:

- having known geological and reservoir characteristics;
- being in close proximity to existing wells so data from the existing wells can be correlated with seismic data on or near the prospect being evaluated; and
- having a potentially meaningful impact on our reserves.

(4) Use Horizontal Drilling and Fracture Stimulations – We believe the use of horizontal drilling and fracture stimulations have enabled us to develop reserves economically such as our Barnett Shale and Wolfcamp gas projects.

When economic conditions are favorable and when we have sufficient capital resources, we believe we can maximize the value of our properties by accelerating drilling activities. This provides us an opportunity to replace reserves at a more rapid pace than existing reserves are produced.

Drilling Activities in 2005

The following table shows our drilling activities, by geographic area, during 2005:

Area	Range (feet)	Number of Gross Wells Drilled	Number of Wells Drilling or Waiting on Completion at December 31, 2005	Gross Productive Wells	Gross Dry Wells
North Texas					
Barnett Shale	7,000 – 8,000	9	5	4	0
Permian Basin					
Carm-Ann/Means	4,000 – 4,500	18	1	17	0
Harris	4,000 – 4,500	1	1	0	0
Fullerton	4,000 – 5,000	12	0	12	0
Wolfcamp Gas	4,300 – 4,500	16	14	2	0
Diamond M (Deep)	6,500 – 7,000	1	1	0	0
Onshore Gulf Coast of Texas					
Yegua	6,300 – 13,000	6	1	1	4
Wilcox	11,000 – 11,500	5	1	4	0
Cook Mountain	11,000 – 15,000	4	1	2	1
Texas Panhandle	11,000 – 11,500	3	0	3	0
		75	25	45	5

From 1993 until mid 2002, we concentrated our activities in the Yegua/Frio/Wilcox gas trends in the onshore gulf coast area of south Texas in Dewitt, Jackson, Lavaca, Victoria and Wharton Counties. Substantially all of our drilling success in south Texas has been in the Yegua/Frio gas trend and we intend to continue drilling additional lower risk 3-D seismic development wells in this trend. Although the successful wells we drilled in the Yegua/Frio trend provided quick payouts of our drilling and completion costs, the reserve lives of the properties in this area have proven to be very short as compared to our properties in the Permian Basin.

Consistent with our strategy of reducing geologic risk, we began to diversify our exploration efforts into other oil and gas trends. However, and as planned, the majority of our drilling in 2005 was in the Permian Basin of west Texas and New Mexico, Fort Worth Basin of north Texas and the onshore gulf coast area of south Texas.

We believe we can more fully develop our existing producing properties in the Permian Basin of west Texas, which have been proven by previous drilling. Collectively, our Permian Basin properties include approximately 42,524 gross (28,361 net) developed acres, which will provide significant exploitation and development opportunities for both oil and natural gas. Additionally, our Permian Basin properties have longer reserve lives than our south Texas properties. Our exploitation and enhancement efforts are conducted primarily on our properties in the Permian Basin of west Texas. We own working interests in these properties ranging from 6.25% to 100%.

During 2005, our Permian Basin activities included:

- utilization of horizontal and fracture stimulation technologies on certain types of reservoirs;
- producing property acquisitions;
- recompleting existing wellbores;
- restimulating producing reservoirs;
- identifying potential infill drilling locations;
- making mechanical improvements to surface facilities and downhole equipment; and
- reviewing the feasibility of applying new drilling and production technologies that could either improve recovery potential or result in the discovery of a new reservoir.

As part of our remedial and enhancement operations in the Permian Basin, we routinely review the performance and economics of our oil and gas properties and, from time to time, we may also renegotiate gas purchase contracts or reconfigure gathering lines. When necessary, we take corrective action, such as:

- shutting in temporarily uneconomic properties;
- plugging wells we believe to be permanently impaired or depleted;
- terminating oil and gas leases that are uneconomic under existing operating conditions; and/or
- selling properties to third parties.

Drilling and Acquisition Costs

The table below shows our oil and gas property acquisition, exploration and development costs for the periods indicated.

Year ended December 31, (in thousands)	**2005**	2004	2003	2002	2001
Proved property acquisition costs	**$ 23,763**	$ 39,763	$ 2,209	$ 48,044	$ 27
Unproved property acquisition costs	**11,743**	7,400	3,831	2,295	3,420
Exploration costs	**15,455**	6,794	3,240	1,291	6,820
Development costs	**26,390**	13,954	5,650	9,308	1,203
	$ 77,351	$ 67,911	$ 14,930	$ 60,938	$ 11,470

Capital Investment Budget for 2006

Our 2006 capital investment budget for properties we owned at March 1, 2006 is estimated to be approximately $103.7 million, which includes $12.6 million for the purchase of leasehold, seismic and other in our areas of activity. The budget will be funded from our estimated operating cash flows and bank borrowings. The amount and timing of expenditures are subject to change based upon market conditions, result of expenditures, new opportunities and other factors.

On a geographic basis, approximately 28% of our projected 2006 capital investment program will be directed toward oil and gas reserves in the Permian Basin of Texas, 44% for the Wolfcamp gas project in the Permian Basin of New Mexico, 4% to gas reserves in east Texas and in the onshore gulf coast area of south Texas, 20% for our north Texas Barnett Shale gas project, and the remaining 4% to other projects.

Resource Gas Projects

We have two resource gas projects in early stages of development. They are the Barnett Shale gas project in the Fort Worth Basin of North Texas and the Wolfcamp gas project in the Permian Basin of New Mexico. These resource gas projects generated approximately 10% of our fourth quarter 2005 daily production (463 BOE per day) and represented approximately 5% of our total reserve value as of December 31, 2005.

We have budgeted approximately $66.6 million for these two resource gas projects in 2006 for the drilling and completion of 66 new wells, pipeline construction and leasehold acquisition.

Fort Worth Basin of North Texas

Barnett Shale Gas Project, Tarrant County, Texas – This project generated approximately 9% of our fourth quarter 2005 daily production (420 BOE per day) and represented approximately 4% of our total reserve value as of December 31, 2005.

Our current leasehold position in the Barnett Shale gas project includes approximately 11,500 gross (3,100 net) acres. We have budgeted approximately $21.1 million for this project in 2006 for the drilling and completion of 18 new wells, pipeline construction and leasehold acquisition. As of January 25, 2006, there were 2 drilling rigs running and 5 wells awaiting completion and pipeline connection in the Barnett Shale gas project.

Permian Basin of New Mexico

Wolfcamp Gas Project, Eddy and Chaves Counties, New Mexico – This project generated approximately 1% of our fourth quarter 2005 daily production (43 BOE per day) and represented approximately 1% of our total reserve value as of December 31, 2005.

Our New Mexico Wolfcamp gas project consists of three areas of mutual interest (AMI's) in which the primary target is the Wolfcamp formation at a depth of approximately 5,000 feet. Our current leasehold position in the project includes approximately 149,000 gross (44,000 net) acres, combined, in Areas 1, 2 and 3. We anticipate participating in the drilling of approximately 48 horizontal wells in New Mexico during 2006. Twenty-four of the wells will be operated by Parallel in Areas 2 and 3, and twenty-four wells in Area 1 will be non-operated. We have budgeted approximately $45.5 million for this project in 2006 to fund the drilling and related leasing and infrastructure activity.

Activity in this horizontal gas project continued to accelerate during the fourth quarter of 2005 and 2006 year-to-date. We have participated in a total of 22 horizontal wells, 3 of which are operated wells and 19 are non-operated. As of January 25, 2006, 10 of the 22 wells were flowing to sales, 4 are being completed, 3 are awaiting completion, and 5 are drilling.

Techniques and procedures utilized in the New Mexico Wolfcamp gas project will continue to be refined, based on available information derived from Areas 1, 2 and 3. Based upon information currently available, we believe this project has the potential to become a multi-well, long-life gas project that will be developed over the next three to five years. Initially, wells are being drilled on 320-acre spacing. After sufficient performance data has been evaluated, down-spacing may prove to be a viable option. We are orienting initial development to accommodate future down-spacing. We are currently running 2 drilling rigs in Area 2 of our New Mexico Wolfcamp gas project. We are also participating in the drilling of 3 non-operated wells in Area 1.

Area 1 – This part of our Wolfcamp gas project consists of approximately 63,000 gross (4,600 net) acres. Our base working interest in this non-operated AMI is approximately 8.5%.

The 10 producing wells mentioned above are all located in Area 1. Eight of these wells are operated by LCX Energy, LLC, and two are operated by EOG Resources Inc. The first 6 wells originally drilled and completed by Perenco, and now operated by LCX Energy, employed large acid stimulations. With the exception of the Thames No. 1H, the acid stimulated wells were relatively poor producers, prompting the need for more aggressive stimulation. Two wells operated by EOG Resources and two wells operated by LCX Energy, have all employed multi-stage, lite-sand fracs and have yielded improved results. The two EOG Resources wells each had average first full-month sales of approximately 2,800 Mcf of gas per day, or approximately 300 Mcf of gas per day net to Parallel. The two LCX Energy wells went on line in November and December of 2005, and the produced volumes have not been released as of this date. LCX Energy's Thames No. 1H well, which was acid stimulated, went to sales in July 2004, has cumulative production of 0.57 Bcfg, and is currently producing approximately 570 gross (40 net) Mcf of gas per day. EOG Resources' Nile 22-1H went to sales in March 2005, has cumulative production of 0.51 Bcfg, and is currently producing approximately 900 gross (135 net) Mcf of gas per day.

Area 2 – This part of the Wolfcamp gas project, which is contiguous to Area 1, is operated by us and consists of approximately 77,000 gross (35,000 net) acres. Our base working interest in this operated AMI is approximately 85.0%.

We initiated well operations on the Seabiscuit No. 1 vertical well in the second quarter of 2005 with the re-entry of a plugged and abandoned well to determine the economic viability of properly stimulated vertical wells and to collect basic data for utilization in horizontal well design. This well is currently awaiting pipeline connection.

Our first 2 horizontal wells in Area 2, the Affirmed No. 1H and the Seabiscuit No. 2H, are both currently drilling in their lateral sections. We are also in process of surveying and preparing to install our own pipeline to gather and transport our gas in Area 2.

Area 3 – This part of the Wolfcamp gas project is located within the original confines of Area 1 and is also operated by us. We have been actively increasing our leasehold position in this area, which now consists of approximately 9,000 gross (5,000 net) acres. Our base working interest in this operated AMI is approximately 85.0%.

We drilled our first well in Area 3 in mid-October 2005. Through a "drill-to-earn" obligation, the well was drilled to a formation deeper than the Wolfcamp, where an unsuccessful completion attempt was made. Subsequently, the well was plugged back and a lateral was drilled in the Wolfcamp formation, where casing was cemented in place. We are now installing a pipeline and expect this well to be completed to sales in March 2006.

Permian Basin of West Texas

The Permian Basin of west Texas generated approximately 50% of our 2005 production and represents approximately 85% of our reserve value as of December 31, 2005. Our significant producing properties in the Permian Basin of west Texas are described below.

Fullerton San Andres Field, Andrews County, Texas – This non-operated property generated approximately 33% of our fourth quarter 2005 daily production and represents approximately 37% of our total proved reserve value as of December 31, 2005.

This property was acquired in December 2002 for approximately $46.1 million. During the fourth quarter of 2004, we acquired additional interests in the property for approximately $20.9 million. Development since the initial acquisition in 2002 has primarily consisted of the re-stimulation of approximately 80 existing producing wells and the drilling of 18 new producing wells.

We have budgeted approximately $1.8 million to fund the drilling and completion of 4 new infill wells and 5 workovers in the field in 2006. Our average working interest in the Fullerton properties is approximately 82%.

Carm-Ann San Andres Field / N. Means Queen Unit, Andrews & Gaines Counties, Texas – These properties generated approximately 11% of our fourth quarter 2005 daily production and represent approximately 12% of our total proved reserve value as of December 31, 2005.

In the fourth quarter 2004 and in 2005, we acquired producing properties in the Carm-Ann San Andres and North Means Queen Unit located in Andrews and Gaines Counties, Texas. The combined aggregate net purchase price was approximately $18.7 million. The properties include 25 leases covering 5,360 gross contiguous acres, with 67 gross producing oil and natural gas wells. This acquisition established a new core operating area that is located within 40 miles of our Midland, Texas, headquarters.

We have budgeted approximately $5.0 million for the Carm-Ann/N. Means Queen properties in 2006 for 9 workovers and 11 new infill wells. Our average working interest in these properties is approximately 77%.

Harris San Andres Field, Andrews and Gaines Counties, Texas – These properties represented approximately 1% of our fourth quarter 2005 daily production and 12% of our total proved reserve value as of December 31, 2005.

In the fourth quarter 2005 and in the first quarter 2006, we acquired properties in the Harris San Andres which includes approximately 6,100 gross acres in Andrews and Gaines Counties, Texas. The leases are approximately one mile from the Carm-Ann properties. Production is from 35 wells and approximately 439 BOE per day, net to Parallel.

We have budgeted approximately $11.1 million for the Harris San Andres properties in 2006 for 4 workovers and 23 new drills.

Diamond M Shallow Leases, Scurry County, Texas – This property generated approximately 1% of our fourth quarter 2005 daily production and represented approximately 9% of our total proved reserve value as of December 31, 2005.

Development activity on this project during 2005 consisted primarily of the conversion of 18 producing wells to injection wells.

We have budgeted only $200,000 in 2006 pending satisfactory waterflood response. Our average working interest in these properties is approximately 66%.

Diamond M Canyon Reef Unit, Scurry County, Texas – This property generated approximately 7% of our fourth quarter 2005 daily production and represented approximately 9% of our total proved reserve value as of December 31, 2005.

A total of $8.3 million has been budgeted in 2006 to fund the workover of 12 wells, the drilling of 6 new wells, the acquisition of a new 3-D seismic survey and associated equipment upgrades. Our average working interest in these properties is approximately 66%.

Other Permian Basin Projects – Other Permian Basin projects generated approximately 6% of our fourth quarter 2005 daily production and represented approximately 6% of our total proved reserve value as of December 31, 2005.

We have budgeted approximately $2.2 million for other Permian Basin properties in 2006, primarily for lease and well equipment and capitalized overhead.

Onshore Gulf Coast of South Texas

Yegua/Frio/Wilcox Gas Project, Jackson, Wharton and Liberty Counties, Texas – This project generated approximately 31% of our fourth quarter 2005 daily production and represented approximately 10% of our total proved reserve value as of December 31, 2005.

We have budgeted approximately $2.8 million for the Yegua/Frio/Wilcox gas project in 2006, for the drilling and completion of 5 wells.

Other Projects

Utah/Colorado CBM (Coal Bed Methane) Gas/Conventional Oil and Gas Projects, Uinta Basin – Our development of this project is expected to begin in the first half of 2006. This project does not yet contribute to our current daily production or reserve value.

As of December 31, 2005, our leasehold acreage position in this project to approximately 197,000 gross acres. It is a multiple zone project consisting of both oil and natural gas targets at a depth of less than 6,000 feet. Seismic and geological data evaluation on this project continues. We expect to drill a test well during the first half of 2006.

We have budgeted approximately $4.2 million for the Utah/Colorado CBM gas project in 2006 for the drilling and completion of 1 well, seismic and leasehold acquisition, and multiple core test holes for coal-bed methane potential. We own and operate 100% of this project.

East Texas Cotton Valley Reef Gas Project – This project contributes minimally to our current daily production and reserve value.

This 3-D seismic gas project is a higher risk profile than our other projects. The objective is the Cotton Valley barrier reef facies found between depths of 16,000 and 18,000 feet. The project consists of approximately 5,000 gross (650 net) acres.

We have budgeted approximately $1.5 million for the Cotton Valley Reef gas project in 2006 for the drilling of 1 well and additional leasehold acquisition. We own an approximate 13.125% working interest in this project.

Oil and Natural Gas Prices

Our revenues, profitability and cash flows are highly dependent on the prices we receive for our oil and natural gas. Generally, oil and natural gas prices improved and stabilized during the period from mid-2000 to the third quarter of 2001, when prices began to decline. During the first quarter of 2002, prices began to increase again and this upward trend in price has continued.

The average wellhead prices we received for the oil and natural gas we produced in 2005, 2004 and 2003 are shown in the table below.

	Average Price Received for the Year Ended December 31,		
	2005	2004	2003
Oil (Bbl)	**$ 51.78**	$ 39.05	$ 29.11
Natural gas (Mcf)	**$ 8.54**	$ 5.85	$ 5.40

The average price we received for our oil sales at March 1, 2006 was approximately $56.38 per Bbl, excluding our hedging activities. At the same date, the average price we were receiving for our natural gas was approximately $9.43 per Mcf, excluding our hedging activities.

There is substantial uncertainty regarding future oil and gas prices and we can provide no assurance that prices will remain at current levels. We have entered into derivative contracts in an attempt to reduce the risk of fluctuating oil and natural gas prices and interest rates.

Employees

In 2005 we added 10 new employees. At March 1, 2006, we had 40 full time employees. Mr. Cambridge, Chairman of the Board of Directors, serves in the capacity of a consultant and not as a full-time employee. We also retain independent land, geological, geophysical and engineering consultants from time to time and expect to continue to do so in the future. Additionally, we retain 2 contract pumpers on a month-to-month basis.

We consider our employee relations to be satisfactory. None of our employees are represented by a union and we have not experienced work stoppages or strikes.

Wells Drilled

The following table shows certain information concerning the number of gross and net wells we drilled during the three-year period ended December 31, 2005.

	Exploratory Wells[1]				Development Wells[2]			
	Productive		Dry		Productive		Dry	
Year Ended December 31,	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2005	**21.0**	**5.32**	**6.0**	**0.64**	**48.0**	**27.5**	—	—
2004	17.0	1.68	4.0	0.95	50.0	31.8	—	—
2003	15.0	5.05	8.0	2.09	3.0	2.6	1.0	0.25

(1) An exploratory well is a well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.

(2) A development well is a well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

All of our drilling is performed on a contract basis by third-party drilling contractors. We do not own any drilling equipment.

At March 14, 2006, we were participating in the completion of 5 gross (1.82 net) wells, 15 gross (7.13 net) wells were awaiting completion and 7 gross (2.49 net) wells were in process of drilling.

Volumes, Prices and Lifting Costs

The following table shows certain information about our oil and natural gas production, average sales prices per Mcf of natural gas and Bbl of oil and the average lifting cost per BOE for the three-year period ended December 31, 2005.

Year ended December 31, (in thousands, except per unit data)	**2005**	2004	2003
Production, Prices and Lifting Costs:			
Oil (Bbls)	**923**	729	629
Natural gas (Mcf)	**3,592**	2,690	3,356
BOE	**1,522**	1,177	1,188
Oil price (per Bbl)(1)	**$ 51.78**	$ 39.05	$ 29.11
Natural gas price (per Mcf)(1)	**$ 8.54**	$ 5.85	$ 5.40
BOE price(1)	**$ 51.57**	$ 37.55	$ 30.66
Average Production (lifting) Cost per BOE	**$ 9.24**	$ 8.06	$ 7.07

(1) Average price received at the wellhead for our oil and natural gas.

In 2005, approximately 61% of our production was oil and 39% was natural gas. The majority of the oil production is from our Permian Basin long life oil assets. The majority of the natural gas production is from our gulf coast short life assets.

The following table summarizes our revenues for each year in the three year period ended December 31, 2005 by product sold.

(in thousands)	**2005**	2004	2003
Oil revenue	**$ 47,800**	$ 28,455	$ 18,300
Effect of oil hedges	**(12,139)**	(7,458)	(1,659)
Natural gas revenue	**30,690**	15,735	18,121
Effect of natural gas hedges	**(201)**	(895)	(907)
	$ 66,150	$ 35,837	$ 33,855

Our oil sales in 2005 represented approximately 61% of our combined oil and gas sales for the year ended December 31, 2005, as compared to 64% in 2004, and 50% in 2003.

Markets and Customers

Our oil and natural gas production is sold at the well site on an as produced basis at market-related prices in the areas where the producing properties are located. We do not refine or process any of the oil or natural gas we produce and all of our production is sold to unaffiliated purchasers on a month-to-month basis.

In the table below, we show the purchasers that accounted for 10% or more of our revenues during the specified years.

	2005	2004	2003
Allegro Investments, Inc.	**14%**	22%	30%
Conoco, Inc.	**12%**	—	—
Texland Petroleum, Inc.	**40%**	43%	33%

We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and natural gas we produce. Other purchasers are available in our areas of operations.

Our future ability to market our oil and natural gas production depends upon the availability and capacity of gas gathering systems and pipelines and other transportation facilities. We are not obligated to provide a fixed or determinable quantity of oil and natural gas under any existing arrangements or contracts.

Our business does not require us to maintain a backlog of products, customer orders or inventory.

Office Facilities

Our principal executive offices are located in Midland, Texas, where we lease approximately 21,640 square feet of office space at 1004 North Big Spring, Suite 400, Midland, Texas 79701. Our current rental rate is $16,650 per month. The lease expires February 28, 2010.

We have two field offices and storage facilities. These two offices are located in Andrews and Snyder, Texas. The current monthly rental rate is $750 for the Andrews's office and $1,200 for the Snyder office. The Andrews office lease expires December 1, 2007. The Snyder office lease expires upon the termination of our trade agreement with the prior operator. We are unable to predict when this agreement will terminate, but we anticipate that it will remain in effect for the life of the properties covered by the agreement.

Competition

The oil and natural gas industry is highly competitive, particularly in the areas of acquiring exploration and development prospects and producing properties. The principal means of competing for the acquisition of oil and natural gas properties are the amount and terms of the consideration offered. Our competitors include major oil companies, independent oil and gas firms and individual producers and operators. Many of our competitors have financial resources, staffs and facilities much larger than ours.

We are also affected by competition for drilling rigs and the availability of related equipment. With relatively high oil and natural gas prices, the oil and gas industry typically experiences shortages of drilling rigs, equipment, pipe and qualified field personnel. Although we are unable to predict when or to what extent our exploration and development activities will be affected by rig, equipment or personnel shortages, we have recently experienced, and continue to experience, delays in some of our planned activities and operations because of these shortages.

Intense competition among independent oil and natural gas producers requires us to react quickly to available exploration and acquisition opportunities. We try to position for these opportunities by maintaining:

- adequate capital resources for projects in our primary areas of operations;
- the technological capabilities to conduct a thorough evaluation of a particular project; and
- a small staff that can respond quickly to exploration and acquisition opportunities.

The principal resources we need for acquiring, exploring, developing, producing and selling oil and natural gas are:

- leasehold prospects under which oil and natural gas reserves may be discovered;
- drilling rigs and related equipment to explore for such reserves; and
- knowledgeable and experienced personnel to conduct all phases of oil and natural gas operations.

Oil and Gas Regulations

Our operations are regulated by certain federal and state agencies. Oil and natural gas production and related operations are or have been subject to:

- price controls;
- taxes; and
- environmental and other laws relating to the oil and gas industry.

We cannot predict how existing laws and regulations may be interpreted by enforcement agencies or court rulings, whether additional laws and regulations will be adopted, or the effect such interpretations or new laws and regulations may have on our business, financial condition or results of operations.

Our oil and natural gas exploration, production and related operations are subject to extensive rules and regulations that are enforced by federal, state and local agencies. Failure to comply with these rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these rules and regulations are frequently amended or reinterpreted, we are not able to predict the future cost or impact of compliance with these laws.

Texas and many other states require drilling permits, bonds and operating reports. Other requirements relating to the exploration and production of oil and natural gas are also imposed. These states also have statutes or regulations addressing conservation matters, including provisions for:

- the unitization of pooling of oil and gas properties;
- the establishment of maximum rates of production from oil and gas wells; and
- the regulation of spacing, plugging and abandonment of wells.

Sales of natural gas we produce are not regulated and are made at market prices. However, the Federal Energy Regulatory Commission regulates interstate and certain intrastate gas transportation rates and services conditions, which affect the marketing of our natural gas, as well as the revenues we receive for sales of our production. Since the mid-1980s, FERC has issued a series of orders, culminating in Order Nos. 636, 636-A, 636-B, and 636-C. These orders, commonly known as Order 636, have significantly altered the marketing and transportation service, including the unbundling by interstate pipelines of the sales, transportation, storage and other components of the city-gate sales services these pipelines previously performed.

One of FERC's purposes in issuing the orders was to increase competition in all phases of the gas industry. Order 636 and subsequent FERC orders issued in individual pipeline restructuring proceedings has been the subject of appeals, the results of which have generally been supportive of the FERC's open-access policy. In 1996, the United States Court of Appeals for the District of Columbia Circuit largely upheld Order No. 636. Because further review of certain of these orders is still possible, and other appeals remain pending, it is difficult to predict the ultimate impact of the orders on Parallel and our gas marketing efforts. Generally, Order 636 has eliminated or substantially reduced the interstate pipelines' traditional role as wholesalers of gas, and has substantially increased competition and volatility in gas markets. While significant regulatory uncertainty remains, Order 636 may ultimately enhance our ability to market and transport our gas, although it may also subject us to greater competition.

Sales of oil we produce are not regulated and are made at market prices. The price we receive from the sale of oil is affected by the cost of transporting the product to market. Effective January 1, 1995, FERC implemented regulations establishing an indexing system for transportation rates for interstate common carrier oil pipelines, which, generally, would index such rates to inflation, subject to certain conditions and limitations. These regulations could increase the cost of transporting oil by interstate pipelines, although the most recent adjustment generally decreased rates. These regulations have generally been approved on judicial review. We are unable to predict with certainty what effect, if any, these regulations will have on us. The regulations may, over time, tend to increase transportation costs or reduce wellhead prices for oil.

We are required to comply with various federal and state regulations regarding plugging and abandonment of oil and gas wells.

Environmental Regulations

Various federal, state and local laws and regulations governing the discharge of materials into the environment, or otherwise relating to the protection of the environment, health and safety, affect our operations and costs. These laws and regulations sometimes:

- require prior governmental authorization for certain activities;
- limit or prohibit activities because of protected areas or species;
- impose substantial liabilities for pollution related to our operations or properties; and
- provide significant penalties for noncompliance.

In particular, our exploration and production operations, our activities in connection with storing and transporting oil and other liquid hydrocarbons, and our use of facilities for treating, processing or otherwise handling hydrocarbons and related exploration and production wastes are subject to stringent environmental regulations. As with the industry generally, compliance with existing and anticipated regulations increases our overall cost of business. While these regulations affect our capital expenditures and earnings, we believe that they do not affect our competitive position in the industry because our competitors are also affected by environmental regulatory programs. Since environmental regulations have historically been subject to frequent change, we cannot predict with certainty the future costs or other future impacts of environmental regulations on our future operations. A discharge of hydrocarbons or hazardous substances into the environment could subject us to substantial expense, including the cost to comply with applicable regulations that require a response to the discharge, such as claims by neighboring landowners, regulatory agencies or other third parties for costs of:

- containment or cleanup;
- personal injury;
- property damage; and
- penalties assessed or other claims sought for natural resource damages.

The following are examples of some environmental laws that potentially impact our operations.

- *Water.* The Oil Pollution Act, or OPA, was enacted in 1990 and amends provisions of the Federal Water Pollution Control Act of 1972 and other statutes as they pertain to prevention of and response to major oil spills. The OPA subjects owners of facilities to strict, joint and potentially unlimited liability for removal costs and certain other consequences of an oil spill, where such spill is into navigable waters, or along shorelines. In the event of an oil spill, into such waters, substantial liabilities could be imposed upon Parallel. States in which Parallel operates have also enacted similar laws. Regulations are currently being developed under the OPA and similar state laws that may also impose additional regulatory burdens on Parallel.

  The FWPCA imposes restrictions and strict controls regarding the discharge of produced waters, other oil and gas wastes, any form of pollutant, and, in some instances, storm water runoff, into waters of the United States. The FWPCA provides for civil, criminal and administrative penalties for any unauthorized discharges and, along with the OPA, imposes substantial potential liability for the costs of removal, remediation or damages resulting from an unauthorized discharge and, along with the OPA, imposes substantial potential liability for the costs of removal, remediation or damages resulting from an unauthorized discharge. State laws for the control of water pollution also provide civil, criminal and administrative penalties and liabilities in the case of an unauthorized discharge into state waters. The cost of compliance with the OPA and the FWPCA have not historically been material to our operations, but there can be no assurance that changes in federal, state or local water pollution control programs will not materially adversely affect us in the future. Although no assurances can be given, we believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition or results of operations.

- *Solid Waste.* Parallel generates non-hazardous solid waste that fall under the requirements of the Federal Resource Conservation and Recovery Act and comparable state statues. The EPA and the states in which we operate are considering the adoption of stricter disposal standards for the type of non-hazardous waste we generate. The Resource Conservation and Recovery Act also govern the generation, management, and disposal of hazardous wastes. At present, we are not required to comply with a substantial portion of the Resource Conservation and Recovery Act requirements because our operations generate minimal quantities of hazardous wastes. However, it is anticipated that additional wastes, which could include wastes currently generated during operations, could in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly disposal and management requirements than are non-hazardous wastes. Such changes in the regulations may result in Parallel incurring additional capital expenditures or operating expenses.

- *Superfund.* The Comprehensive Environmental Response, Compensation, and Liability Act, sometimes called CERCLA or Superfund, imposes liability, without regard to fault or the legality of the original act, on certain classes of persons in connection with the release of a hazardous substance into the environment. These persons include the current owner or operator of any site where a release historically occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In the course of our ordinary operations, we may have managed substances that may fall within CERCLA's definition of a hazardous substance. We may be jointly and severally liable under CERCLA for all or part of the costs required cleaning up sites where we disposed of or arranged for the disposal of these substances. This potential liability extends to properties that we owned or operated as well as to properties owned and operated by others at which disposal of Parallel's hazardous substances occurred.

Parallel may also fall into the category of a current owner or operator. We currently own or lease numerous properties that for many years have been used for exploring and producing oil and gas. Although we believe we use operating and disposal practices standard in the industry, hydrocarbons or other wastes may have been disposed of or released by us on or under properties that we have owned or leased. In addition, many of these properties have been previously owned or operated by third parties who may have disposed of or released hydrocarbons or other wastes at these properties. Under CERCLA, and analogous state laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by prior owners or operators, to clean up contaminated property, including contaminated groundwater, or to perform remedial plugging operations to prevent future contamination.

Item 1a. Risk Factors

Risks Related to Our Business

The volatility of the oil and natural gas industry may have an adverse impact on our operations.

Our revenues, cash flows and profitability are substantially dependent upon prevailing prices for oil and natural gas. In recent years, oil and natural gas prices and, therefore, the level of drilling, exploration, development and production, have been extremely volatile. Any significant or extended decline in oil or natural gas prices will have a material adverse effect on our business, financial condition and results of operations and could impair access to future sources of capital. Volatility in the oil and natural gas industry results from numerous factors over which we have no control, including;

- the level of oil and natural gas prices, expectations about future oil and natural gas prices and the ability of international cartels to set and maintain production levels and prices;
- the cost of exploring for, producing and transporting oil and natural gas;
- the level and price of foreign oil and natural gas transportation;
- available pipeline and other oil and natural gas transportation capacity;
- weather conditions;
- international political, military, regulatory and economic conditions;
- the level of consumer demand;
- the price and the availability of alternative fuels;
- the effect of worldwide energy conservation measures; and
- the ability of oil and natural gas companies to raise capital.

Significant declines in oil and natural gas prices for an extended period may:

- impair our financial condition, liquidity, ability to finance planned capital expenditures and results of operations;
- reduce the amount of oil and natural gas that we can produce economically;
- cause us to delay or postpone some of our capital projects;
- reduce our revenues, operating income and cash flow; and
- reduce the carrying value of our oil and natural gas properties.

No assurance can be given that current levels of oil and natural gas prices will continue. We expect oil and natural gas prices, as well as the oil and natural gas industry generally, to continue to be volatile.

We must replace oil and natural gas reserves that we produce. Failure to replace reserves may negatively affect our business.

Our future performance depends in part upon our ability to find, develop and acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves decline as they are depleted and we must locate and develop or acquire new oil and natural gas reserves to replace reserves being depleted by production. No assurance can be given that we will be able to find and develop or acquire additional reserves on an economical basis. If we cannot economically replace our reserves, our results of operations may be materially adversely affected.

We are subject to uncertainties in reserve estimates and future net cash flows.

There is substantial uncertainty in estimating quantities of proved reserves and projecting future production rates and the timing of development expenditures. No one can measure underground accumulations of oil and natural gas in an exact way. Accordingly, oil and natural gas reserve engineering requires subjective estimations of those accumulations. Estimates of other engineers might differ widely from those of our independent petroleum engineers, and our independent petroleum engineers may make material changes to reserve estimates based on the results of actual drilling, testing, and production. As a result, our reserve estimates often differ from the quantities of oil and natural gas we ultimately recover. Also, we make certain assumptions regarding future oil and natural gas prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Some of our reserve estimates are made without the benefit of a lengthy production history and are calculated using volumetric analysis. Those estimates are less reliable than estimates based on a lengthy production history.

Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay and an estimation of the productive area.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- the amount and timing of actual production;
- supply and demand of oil and natural gas;
- limits of increases in consumption by natural gas purchasers; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Competition in the oil and natural gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do.

We operate in the highly competitive areas of oil and natural gas acquisition, development, exploitation, exploration and production. The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and natural gas companies in each of the following areas:

- seeking to acquire desirable producing properties or new leases for future exploration;
- marketing our oil and natural gas production;
- integrating new technologies; and
- seeking to acquire the equipment and expertise necessary to develop and operate our properties.

Many of our competitors have financial, technological and other resources substantially greater than ours, and some of them are fully integrated oil and natural gas companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

We do not control all of our operations and development projects.
Substantially all of our business activities are conducted through joint operating agreements under which we own partial interests in oil and natural gas wells.

At December 31, 2005, we owned interests in 401 gross (292.76 net) oil and natural gas wells for which we were the operator and 708 gross (215.25 net) oil and natural gas wells where we were not the operator.

If we do not operate wells in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations, or an operator's breach of the applicable agreements, could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's:

- timing and amount of capital expenditures;
- expertise and financial resources;
- inclusion of other participants in drilling wells; and
- use of technology.

Since we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

Our business involves many operating risks, which may result in substantial losses, and insurance may be unavailable or inadequate to protect us against these risks.
Our operations are subject to hazards and risks inherent in drilling for, producing and transporting oil and natural gas, such as:

- fires;
- natural disasters;
- explosions;
- pressure forcing oil or natural gas out of the wellbore at a dangerous velocity coupled with the potential for fire or explosion;
- weather;
- failure of oilfield drilling and service tools;
- changes in underground pressure in a formation that causes the surface to collapse or crater;
- pipeline ruptures or cement failures;
- environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases; and
- availability of needed equipment at acceptable prices, including steel tubular products.

Any of these risks can cause substantial losses resulting from:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We do not insure against the loss of oil or natural gas reserves as a result of operating hazards or insure against business interruption. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operations.

The oil and natural gas industry is capital intensive.
The oil and natural gas industry is capital intensive. We make substantial capital expenditures for the acquisition, exploration for and development of oil and natural gas reserves.

Historically, we have financed capital expenditures primarily with cash generated by operations, proceeds from bank borrowings and sales of our equity securities. In addition, we may consider selling non-core assets to raise additional operating capital. From time to time, we may also reduce our ownership interests in 3-D seismic and other projects in order to reduce our capital expenditure requirements, depending on our working capital needs.

Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

Any one of these variables can materially affect our ability to borrow under our revolving credit facility.

If our revenues or the borrowing base under our revolving credit facility decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to undertake or complete future drilling projects. We may, from time to time, seek additional financing, either in the form of increased bank borrowings, sale of debt or equity securities or other forms of financing and there can be on assurance as to the availability or terms of any additional financing upon terms acceptable to us.

There are risks in acquiring producing properties, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of management attention, increasing the scope, geographic diversity and complexity of our operations and incurrence of additional debt.
Our business strategy includes growing our reserve base through acquisitions. Our failure to integrate acquired businesses successfully into our existing business, or the expense incurred in consummating future acquisitions, could result in unanticipated expenses and losses. In addition, we may assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

We are continually investigating opportunities for acquisitions. In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Our ability to make future acquisitions may be constrained by our ability to obtain additional financing.

Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expense, all of which could have a material adverse effect on our financial condition and operating results.

The marketability of our natural gas production depends on facilities that we typically do not own or control.
The marketability of our natural gas production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. We generally deliver natural gas through natural gas gathering systems and natural gas pipelines that we do not own. Our ability to produce and market natural gas on a commercial basis could be harmed by any significant change in the cost or availability of such systems and pipelines.

We are subject to many restrictions under our revolving credit facility.
We may depend on our revolving credit facility for future capital needs. As required by our revolving credit facility with our bank lenders, we have pledged substantially all of our oil and natural gas properties as collateral to secure the payment of our indebtedness. The revolving credit facility restricts our ability to obtain additional financing, making investments, lease equipment, sell assets and engage in business combinations. We are also required to comply with certain financial covenants and ratios. The revolving credit facility prohibits us from declaring or paying dividends on our common stock. Although we are currently in compliance with these covenants, in the past we have had to request waivers from our banks because of our non-compliance with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond or control. Our failure to comply with any of the restrictions and covenants under the revolving credit facility could result in a default under the revolving credit facility, which could cause all of our existing indebtedness to be immediately due and payable.

The revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders, based upon projected revenues from the oil and natural gas properties securing our loan. The lenders can adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Any increase in the borrowing base requires the consent of all lenders. If all lenders do not agree on an increase, then the borrowing base will be the lowest borrowing base determined by each lender. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties and no assurance can be given that we would be able to make any mandatory principal prepayments required under the revolving credit facility.

If we default under our revolving credit facility, the lenders could foreclose on, and acquire control of, substantially all of our assets.
The lenders under our revolving credit facility have liens on substantially all of our assets. As a result of the liens held by our revolving credit facility lenders, if we fail to meet our payment or other obligations under the revolving credit facility, those lenders would be entitled to foreclose on substantially all of our assts and liquidate those assets.

Our producing properties are geographically concentrated.
A substantial portion of our proved oil and natural gas reserves are located in the Permian Basin of west Texas and eastern New Mexico. Specifically, at December 31, 2005, approximately 85% of the discounted present value of our proved reserves were located in the Permian Basin. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells due to mechanical problems, damages to the current producing reservoirs, significant governmental regulation, including any curtailment of production, or interruption of transportation of oil or natural gas produced from the wells.

Derivative activities create a risk of financial loss.
In order to manage our exposure to price risks in the marketing of our oil and natural gas, we have in the past and expect to continue to enter into oil and natural gas price risk management arrangements with respect to a portion of our expected production. We use derivative arrangements such as swaps, puts and collars that generally result in a fixed price or a range of minimum and maximum price limits over a specified time period. Certain derivative contracts may limit the benefits we will realize if actual prices received are above the contract price. In a typical derivative transaction utilizing a swap arrangement, we will have the right to receive from the counterparty, the excess of the fixed price specified in the contract over a floating price based on a market index, multiplied by the quantity identified in the derivative contract. If the floating price exceeds the fixed price, we are required to pay the counterparty this difference multiplied by the quantity identified in the derivative. Derivative arrangements could prevent us from receiving the full advantage of increases in oil or natural gas prices above the fixed amount specified in the derivative. In addition, these transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- the counterparties to our future contracts fail to perform under the contract; or
- a sudden, unexpected event materially impacts oil or natural gas prices.

In the past, some of our derivative contracts required us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations exceeded certain levels. Future collateral requirements are uncertain but will depend on arrangements with our counterparties and highly volatile natural gas and oil prices.

We are subject to complex federal, state and local laws and regulations that could adversely affect our business.
Extensive federal, state and local regulation of the oil and natural gas industry significantly affects our operations. In particular, our oil and natural gas exploration, development and production, are subject to stringent environmental regulations. These regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and natural gas wells and other related facilities. These regulations may become more demanding in the future. Matters subject to regulation include:

- discharge permits for drilling operations;
- drilling bonds;
- spacing of wells;
- unitization and pooling of properties;
- environmental protection;
- reports concerning operations; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property damage;
- oil spills;
- discharge of hazardous materials;
- reclamation costs;
- remediation and clean-up costs; and
- other environmental damages.

Failure to comply with these laws and regulations also may result in the suspension or terminations of our operations and subject us to administrative, civil and criminal penalties. Further, these laws and regulations could change in ways that substantially increase our costs. Any of these liabilities, penalties, suspensions, terminations or regulatory changes could make it more expensive for us to conduct our business or cause us to limit or curtail some of our operations.

Declining oil and natural gas prices may cause us to record ceiling test write-downs.
We use the full cost method of accounting to account for our oil and natural gas operations. This means that we capitalize the costs to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the capitalized costs of oil and natural gas properties may not exceed a ceiling limit, which is based on the present value of estimated future net revenues, net of income tax effects, from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties. These rules generally require pricing future oil and natural gas production at unescalated oil and natural gas prices in effect at the end of each fiscal quarter, with effect given to cash flow hedge positions. If capitalized costs of oil and natural gas properties, as adjusted for asset retirement obligations, exceed the ceiling limit we must charge the amount of the excess against earnings. This is called a ceiling test write-down. This non-cash impairment charge does not affect cash flow from operating activities, but it does reduce stockholders' equity. Impairment charges cannot be restored by subsequent increases in the prices of oil and natural gas.

The risk that will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices decline. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves.

We did not recognize impairment in 2005. We cannot assure you that we will not experience ceiling test write-downs in the future.

Terrorist activities may adversely affect our business.

Terrorist activities, including events similar to those of September 11, 2001, or armed conflict involving the United States may adversely affect our business activities and financial condition. If events of this nature occur and persist, the resulting political and social instability could adversely affect prevailing oil and natural gas prices and cause a reduction in our revenues. In addition, oil and natural gas production facilities, transportation systems and storage facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our operations is destroyed or damaged. Costs associated with insurance and other security measure may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

We are highly dependent upon key personnel.

Our success is highly dependent upon the services, efforts and abilities of key members of our management team. Our operations could be materially and adversely affected if one or more of these individuals become unavailable for any reason.

We do not have employment agreements or long term contractual arrangements with any of our officers or other key employees. In periods of improving market conditions, our ability to obtain and retain qualified consultants on a timely basis may be adversely affected.

Our future growth and profitability will also be dependent upon our ability to attract and retain other qualified management personnel and to effectively manage our growth. There can be no assurance that we will be successful in doing so.

Part of our business is seasonal in nature.

Weather conditions affect the demand for and price of oil and natural gas and can also delay drilling activities, temporarily disrupting our overall business plans. Demand for oil and natural gas is typically higher during winter months than summer months. However, warm winters can also lead to downward price trends. As a result, our results of operations may be adversely affected by seasonal conditions.

Our oil and natural gas operations are subject to many inherent risks.

Oil and natural gas drilling activities and production operations are highly speculative and involve a high degree of risk. These operations are marked by unprofitable efforts because of dry holes and wells that do not produce oil or natural gas in sufficient quantities to return a profit. The success of our operations depends, in part, upon the ability of our management and technical personnel. The cost of drilling, completing and operating wells is often uncertain. There is no assurance that our oil and natural gas drilling of acquisition activities will be successful, that any production will be obtained, or that any such production, if obtained, will be profitable.

Our operations are subject to all of the operating hazards and risks normally incident to drilling for and producing oil and natural gas. These hazards and risks include, but are not limited to:

- encountering unusual or unexpected formations and pressures;
- explosions, blowouts and fires;
- pipe and tubular failures and casing collapses;
- environmental pollution; and
- personal injuries.

Any one of these potential hazards could result in accidents, environmental damage, personal injury, property damage and other harm that could result in substantial liabilities to us.

As is customary in the industry, we maintain insurance against some, but not all, of these hazards. We maintain general liability insurance and obtain Operator's Extra Expense insurance on a well-by-well basis. We carry insurance against certain pollution hazards, subject to our insurance policy's terms, conditions and exclusions. If we sustain an uninsured loss or liability, our ability to operate could be materially adversely affected.

Our oil and natural gas operations are not subject to renegotiation of profits or termination of contracts at the election of the federal government.

Failure to maintain effective internal controls could have a material adverse effect on our operations.

Section 404 of the Sarbanes-Oxley Act requires annual management assessments of the effectiveness of our internal control over financial reporting and a report by our independent auditors addressing these assessments. During the course of our preparation of this Annual Report on Form 10-K, we identified a material weakness with respect to our hedge accounting under SFAS No. 133. Effective internal controls are necessary for us to produce reliable financial reports. If, as a result of deficiencies in our internal controls, we cannot provide reliable financial reports, our business decision process may be adversely affected, our business and operating results could be harmed, investors could lose confidence in our reported financial information, and the price of our stock could decrease as a result. We are in the process of remediating our internal control weakness. Although we can provide no assurance as to the timing or ultimate success of our remediation efforts, we believe that we will be able to correct the identified deficiency in our internal controls.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our revolving credit facility and second lien term loan facility contain a number of significant covenants that, among other things, restrict our ability to:

- dispose of assets;
- incur additional indebtedness;
- restrictions on all retained earnings and net income for payment of dividends on our common stock;
- create liens on our assets;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or other securities;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- engage in other specified corporate activities.

Also, our revolving credit facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financing, make needed capital expenditures, withstand a future downturn in our business or economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the revolving credit facility impose on us. A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under the revolving credit facility. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under the revolving credit facility. The accelerated debt would become immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us.

We do not pay dividends on our common stock.

We have never paid dividends on our common stock, and do not intend to pay cash dividends on the common stock in the foreseeable future. Net income from our operations, if any, will be used for the development of our business, including capital expenditures and to retire debt. Any decisions to pay dividends on the common stock in the future will depend upon our profitability at the time, the available cash and other factors. Our ability to pay dividends on our common stock is further limited by the terms of our revolving credit facility and our second lien term loan facility.

Changes in control may be discouraged.

Our certificate of incorporation, our bylaws and the Delaware General Corporation Law contain provisions that may discourage other persons from initiating a tender offer or takeover attempt that a stockholder might consider to be in the best interest of all stockholders, including takeover attempts that might result in a premium to be paid over the market price of our stock.

On October 5, 2000, our Board of Directors adopted a stockholder rights plan. The plan is designed to protect Parallel from unfair or coercive takeover attempts and to prevent a potential acquirer from gaining control of Parallel without fairly compensating all of the stockholders. The plan authorized 50,000 shares of $0.10 par Series A Preferred Stock Purchase Rights. A dividend of one Right for each share of our outstanding common stock was distributed to stockholders of record at the close of business on October 16, 2000. If a public announcement is made that a person has acquired 15% or more of Parallel's common stock, or a tender or exchange offer is made for 15% of more of the common stock, each Right entitles the holder to purchase from the company one one-thousandth of a share of Series A Preferred Stock, at an exercise price of $26.00 per one one-thousandth of a share, subject to adjustment. In addition, under certain circumstances, the rights entitle the holders to buy Parallel's stock at a 50% discount. See Note 11 to consolidated financial statements.

We are authorized to issue 10.0 million shares of preferred stock; there are no outstanding shares as of December 31, 2005. Our Board of Directors has total discretion in the issuance and the determination of the rights and privileges of any shares of preferred stock which might be issued in the future, which rights and privileges may be detrimental to the holders of the common stock. It is not possible to state the actual effect of the authorization and issuance of a new series of preferred stock upon the rights of holders of the common stock and other series of preferred stock unless and until the Board of Directors determines the attributes of any new series of preferred stock and the specific rights of its holders. These effects might include:

- restrictions on dividends on common stock and other series of preferred stock if dividends on any new series of preferred stock have not been paid;
- dilution of the voting power of common stock and other series of preferred stock to the extent that a new series of preferred stock has voting rights, or to the extent that any new series of preferred stock is convertible into common stock;
- dilution of the equity interest of common stock and other series of preferred stock; and
- limitation on the right of holders of common stock and other series of preferred stock to share in Parallel's assets upon liquidation until satisfaction of any liquidation preference attributable to any new series of preferred stock.

The issuance of preferred stock in the future could discourage, delay or prevent a tender offer, proxy contest or other similar transaction involving a potential change in control of Parallel that might be viewed favorably by stockholders.

Item 1b. Unresolved Staff Comments

We have not received any written comments from the staff of the Securities and Exchange Commission that remain unresolved.

Item 2. Properties

General

Our principal properties consist of developed and undeveloped oil and natural gas leases and the reserves associated with these leases. Generally, developed oil and natural gas leases remain in force so long as production is maintained. Undeveloped oil and natural gas leaseholds are generally for a primary term of five or ten years. In most cases, we can extend the term of our undeveloped leases by paying delay rentals or by producing reserves that we discover under our leases.

Producing Wells and Acreage

We have presented the following table to provide you with a summary of the producing oil and natural gas wells and the developed and undeveloped acreage in which we owned an interest at December 31, 2005. We have not included in the table acreage in which our interest is limited to options to acquire leasehold interests, royalty or similar interests.

	Producing Wells				Acreage			
	Oil(1)		Gas		Developed		Undeveloped	
	Gross	Net(2)	Gross	Net(2)	Gross	Net(3)	Gross	Net(3)
Texas	621	313.8	104	36.50	59,603	36,565	37,028	9,221
Colorado	—	—	—	—	—	—	14,080	14,080
New Mexico	—	—	18	3.39	3,197	367	145,591	44,076
Utah	—	—	—	—	—	—	183,397	147,257
Total	621	313.8	122	39.89	62,800	36,932	380,096	214,634

(1) Does not include 366 wells that were shut in or temporarily abandoned as of December 31, 2005.

(2) Net wells are computed by multiplying the number of gross wells by our working interest in the gross wells.

(3) Parallel's net acres are computed by multiplying the number of gross acres by our working interest.

At December 31, 2005, we owned interests in 401 gross (292.76 net) oil and natural gas wells for which we were the operator and 708 gross (215.25 net) oil and natural gas wells where we were not the operator.

The operator of a well has significant control over its location and the timing of its drilling. In addition, the operator receives fees from other working interest owners as reimbursement for general and administrative expenses for operating the wells.

Except for our oil and natural gas leases, we do not own any patents, licenses, franchises or concessions which are significant to our oil and natural gas operations.

Title to Properties

As in customary in the oil and natural gas industry, we make only a cursory review of title to undeveloped oil and natural gas leases at the time they are acquired. These cursory title reviews, while consistent with industry practices, are necessarily incomplete. We believe that it is not economically feasible to review in depth every individual property we acquire, especially in the case of producing property acquisitions covering a large number of leases. Ordinarily, when we acquire producing properties, we focus our review efforts on properties believed to have higher values and will sample the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential defects nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. In the case of producing property acquisitions, inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. In the case of undeveloped leases or prospects we acquire, before any drilling commences, we will usually cause a more thorough title search to be conducted, and any material defects in title that are found as a result of the title search are generally remedied before drilling a well on the lease commences. We believe that we have good title to our oil and natural gas properties, some of which are subject to immaterial encumbrances, easements and restrictions. The oil and natural gas properties we own are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. We do not believe that any of these encumbrances or burdens will materially affect our ownership or the use of our properties.

Oil and Natural Gas Reserves

For the year ended December 31, 2005, our oil and natural gas reserves were estimated by Cawley Gillespie & Associates, Inc., Fort Worth, Texas.

At December 31, 2005, our total estimated proved reserves were approximately 21.2 MMBbls of oil and 25.2 Bcf of gas, or 25.4 MMBoes.

The information in the following table provides you with certain information regarding our proved reserves as estimated by Cawley Gillespie & Associates, Inc. at December 31, 2005.

(in thousands)	Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved
Oil (MBbls)	13,355	259	7,578	21,192
Gas (MMcf)	15,959	1,287	7,991	25,237
MBOE	16,015	474	8,910	25,399

Estimates of our proved reserves and future net revenues are made using sales prices and costs, estimated to be in effects as of the date of such reserve estimates that are held constant throughout the life of the properties, except to the extent a contract specifically provides for escalation. The average prices utilized in the estimation of our reserve calculations as of December 31, 2005 were $56.09 per Bbl of oil and $8.68 per Mcf of natural gas.

For additional information concerning our estimated proved oil and natural gas reserves, you should read Note 16 to the consolidated financial statements. See also Item 8 Financial Statements and Supplementary Data on page 54 of this Annual Report on Form 10-K.

The reserve data in this report represent estimates only. Reservoir engineering is a subjective process. There are numerous uncertainties inherent in estimating our oil and natural gas reserves and their estimated values. Many factors are beyond our control. Estimating underground accumulations of oil and natural gas cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment and the costs we actually incur in the development of our reserves. As a result, estimates of different engineers often vary. In addition, estimates of reserves are subject to revision by the results of drilling, testing and production after the date of the estimates. Consequently, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of estimates is highly dependent upon the accuracy of the assumptions upon which they were based.

The volume of production from oil and natural gas properties declines as reserves are produced and depleted. Unless we acquire properties containing proved reserves or conduct successful drilling activities, our proved reserves will decline as we produce our existing reserves. Our future oil and natural gas production is highly dependent upon our level of success in acquiring or finding additional reserves.

We do not have any oil or natural gas reserves outside the United States. Our oil and natural gas reserves and production are not subject to any long term supply or similar agreements with foreign governments or authorities.

Our estimated reserves have not been filed with or included in reports to any federal agency other than the SEC.

Item 3. Legal Proceedings

On December 30, 2005, we were named as a defendant in a lawsuit filed in the 352nd Judicial District Court of Tarrant County, Texas, Cause No. 352-215616-05, AFE Oil and Gas, L.L.C. (aka AFE Oil and Gas, LLC) v. Premium Resources II, L.P., Premium Resources, Inc., Danay Covert, Nick Morris, William D. Middleton, Dale Resources, L.L.C., and Parallel Petroleum, Inc.

In this suit, the plaintiff alleges breach of fiduciary duty, fraud and conspiracy to defraud, breach of contract, constructive trust, suit to remove cloud from title, declaratory judgment, alter ego, and statutory fraud and seeks recovery of an unspecified amount of actual damages, special damages, consequential damages, exemplary damages, attorneys' fees, pre-judgment and post-judgment interest and costs. Generally, the plaintiff alleges that it owns a 5.5% overriding royalty interest in certain oil and gas properties known as the "Square Top LP" and the "West Fork LP" leases located in Tarrant County, Texas. The plaintiff alleges that the defendants (other than Dale Resources and Parallel) wrongfully and intentionally allowed these original oil and gas leases to terminate, causing the termination of plaintiff's overriding royalty interest in each lease. The plaintiff further alleges that the defendants (other than Dale Resources and Parallel) failed to drill wells necessary to maintain the original leases in force and that after the original leases were allowed to terminate, the defendants (other than Dale Resources and Parallel) then acquired new oil and gas leases covering these same oil and gas properties, which were subsequently assigned to Dale Resources. Thereafter, Dale Resources allegedly assigned a portion of these new leases to Parallel.

In addition to seeking unspecified monetary damages, the plaintiff also seeks to impose a constructive trust for its benefit on the new oil and natural gas leases and seeks a judicial declaration that either (1) the plaintiff is the owner of an overriding royalty interest in the new leases or that (2) the original leases and plaintiff's interest in the original leases are still in effect. The plaintiff also claims that the new leases constitute a cloud on plaintiff's title and seeks to have that cloud removed. Based on our present understanding of this case, we believe that we have substantial defenses to the plaintiff's claims and intend to vigorously assert these defenses. However, if the plaintiff is awarded an interest in the new leases, we could potentially become liable for the payment to plaintiff of the portion of production proceeds attributable to plaintiff's interest received by us. On the other hand, if the plaintiff prevails on its claim that the original leases are still in effect, our interest in the new leases could become subject to forfeiture. Based on the information known to date, we have not established a reserve for this matter.

From time to time, we are party to ordinary routine litigation incidental to our business. We are currently a defendant in one other lawsuit. We do not believe the ultimate outcome of this lawsuit will have a material adverse effect on our financial condition or results of options. We are not aware of any other threatened litigation and we have not been a party to any bankruptcy, receivership, reorganization, adjustment or similar proceeding.

Item 4. Submission of Matters to a Vote of Security Holders

We did not submit any matter to a vote of our stockholders during the fourth quarter of 2005.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholders Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock trades on the Nasdaq National Market under the symbol PLLL. The following table shows, for the periods indicated, the high and low closing sales prices for the common stock as reported by Nasdaq.

	Price Per Share	
	High	Low
2003		
First Quarter	$ 3.10	$ 2.51
Second Quarter	$ 4.03	$ 2.40
Third Quarter	$ 3.86	$ 3.15
Fourth Quarter	$ 4.49	$ 3.19
2004		
First Quarter	$ 4.67	$ 3.60
Second Quarter	$ 5.35	$ 3.83
Third Quarter	$ 5.68	$ 4.38
Fourth Quarter	$ 5.60	$ 4.83
2005		
First Quarter	**$ 6.30**	**$ 6.02**
Second Quarter	**$ 7.87**	**$ 7.52**
Third Quarter	**$ 11.75**	**$ 11.24**
Fourth Quarter	**$ 15.29**	**$ 14.60**

The last sale price of our common stock on March 14, 2006 was $16.99 per share, as reported on the Nasdaq National Market.

As of March 14, 2006, there were approximately 1,431 stockholders of record.

Dividends

We have not paid, and do not intend to pay in the foreseeable future, cash dividends on our common stock. The revolving credit facility and second lien term loan facility we have with our lenders prohibit the payment of dividends on the common stock. See "Risks Related to Our Business – We do not pay dividends on our common stock" on page 28 and "Management's Discussion and Analysis of Financial Condition and Results of Operation – Capital Resources and Liquidity" on page 46.

Equity Compensation Plans

At December 31, 2005, a total of 1,754,070 shares of common stock were authorized for issuance under our equity compensation plans. In the table below, we describe certain information about these shares and the equity compensation plans which provide for their authorization and issuance. You can find descriptions of our stock grant and stock option plans beginning on page 68.

	(a)	(b)	(c)
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders(1)	1,216,346	$ 5.29	101,016
Equity compensation plans not approved by security holders	436,708 (2)	$ 4.08	—
Total	1,653,054	$ 4.97	101,016

(1) Includes the following plans: 2004 Non-Employee Director Stock Grant Plan; 1992 Stock Option Plan; 1997 Non-employee Directors Stock Option Plan; 1998 Stock Option Plan and; 2001 Non-employee Directors Stock Option Plan.

(2) These shares include an aggregate of 200,000 shares of common stock underlying stock options granted in June, 2001 to non-officer employees pursuant to Parallel's Employee Stock Option Plan. The Employee Stock Option Plan is the only equity compensation plan in effect that was adopted without approval of our stockholders. Directors and officers of Parallel are not eligible to participate in this plan. A description of the material features of this plan can be found under the caption "Employee Stock Option Plan" on page 71. The total number of shares shown also includes 136,708 shares of common stock underlying a stock purchase warrant we issued to an investment banking firm in November, 2001 and 100,000 shares of common stock underlying a stock purchase warrant we issued to the same investment banking firm in December, 2003. These warrants were issued under financial advisory services agreements with the investment banking firm, and not under employee or director compensation plans. All of the warrants contain customary provisions providing for adjustments of the exercise price and the number and type of securities issuable upon exercise of the warrants if any one or more of certain specified events occur. The warrants also grant to the holder certain registration rights for the securities issuable upon exercise of the warrants.

Sale of Unregistered Securities

At Parallel's annual meeting of stockholders held on June 22, 2004, the stockholders approved the Parallel Petroleum Corporation 2004 Non-Employee Director Stock Grant Plan. You can find a description of this plan on page 68. Historically, Director's fees had been paid solely in cash. However, upon approval of the plan by the stockholders, we began paying an annual retainer fee to each non-employee Director in the form of common stock having a value of $25,000. Only Directors of Parallel who are not employees of Parallel or any of its subsidiaries are eligible to participate in the plan. Under the plan, each non-employee Director is entitled to receive an annual retainer fee consisting of shares of common stock that are automatically granted on the first day of July in each year. The actual number of shares received is determined by dividing $25,000 by the average daily closing price of the common stock on the Nasdaq Stock Market for the ten consecutive trading days commencing fifteen trading days before the first day of July of each year. On July 1, 2005, and in accordance with the terms of the plan, we issued a total of 11,596 shares of common stock to four non-employee Directors as follows: Jeffrey G. Shrader – 2,899 shares; Dewayne Chitwood – 2,899 shares; Martin B. Oring – 2,899 shares; and Ray M. Poage – 2,899 shares. The shares of common stock were issued without registration under the Securities Act of 1933, as amended, in reliance on the exemption provided by Section 4(2) of the Securities Act of 1933, as amended. Generally, shares issued under this plan are not transferable as long as the non-employee Director holding the shares remains a Director of Parallel. Certificates evidencing the shares bear restrictive legends.

On May 4, 2005, we mailed notice that we would redeem all 950,000 outstanding shares of our 6% Convertible Preferred Stock on June 6, 2005 (the "Redemption Date"), at a price of $10.00 per share, plus cash in an amount equal to all accumulated and unpaid dividends on the preferred stock up to the Redemption Date. As permitted under the terms of the preferred stock, all holders of the preferred stock elected to convert their shares of preferred stock into approximately 2.8571 shares of common stock for each share of preferred stock converted, plus cash for any fractional share and for all accumulated and unpaid dividends up to the Redemption Date. Dividends on the preferred stock ceased to accrue, and the preferred stock is not deemed outstanding from and after the Redemption Date. As a result of the holders' election to convert their shares of preferred stock into common stock, we issued a total of 2,714,280 shares of common stock to such holders and paid aggregate accrued dividends in the amount of $270,750.

We did not engage any underwriters, brokers, agents or finders in connection with the redemption of the preferred stock or the issuance of the common stock upon conversion of the preferred stock.

The preferred stock was sold in October 1998 solely to accredited investors. The shares of common stock issued upon conversion of the Preferred Stock were issued in reliance upon the exemptions from registration contained in Section 3(a)(9) and Section 4(2) of the Securities Act of 1933, as amended.

Repurchase of Equity Securities

Neither we nor any "affiliated purchaser" repurchased any of our equity securities during the fourth quarter of the fiscal year ended December 31, 2005.

Item 6. Selected Financial Data

As described under "Financial Statement Restatement" beginning on Page 4 and as further disclosed in Note 18 on Page 108 [F-29] in the Notes to the Consolidated Financial Statements, we restated our financial statements for the year ended December 31, 2004 and other financial information including quarterly information for the quarters ended September 30, June 30 and March 31 of 2005 and the quarters ended December 31 and September 30 of 2004.

In the table below, we provide you with selected historical financial data. We have prepared this information using the audited consolidated financial statements for the five-year period ended December 31, 2005. It is important that you read this data along with our consolidated financial statements and related notes, and "Management's Discussion and Analysis of Financial Condition and Results of Operations" under Item 7 below. The selected financial data provided are not necessarily indicative of our future results of operations or financial performance.

Year ended December 31, (in thousands, except per share and per unit data)	2005	2004	2003	2002(1)	2001(2)
Consolidated Income Statements Data:		*(restated)*			
Operating revenues	**$ 66,150**	$ 35,837	$ 33,855	$ 12,106	$ 17,840
Operating expenses	**$ 33,085**	$ 23,571	$ 21,138	$ 11,250	$ 28,405
Income (loss) before cumulative effect of change in accounting principle	**$ (1,589)**	$ 2,271	$ 7,664	$ 18,701	$ (4,708)
Net income (loss)	**$ (1,589)**	$ 2,271	$ 7,602	$ 18,701	$ (4,708)
Cumulative preferred stock dividend	**$ (271)**	$ (572)	$ (580)	$ (585)	$ (585)
Net income (loss) available to common stockholders	**$ (1,860)**	$ 1,699	$ 7,022	$ 18,116	$ (5,292)
Net income (loss) per common share before cumulative effect of change in accounting principle					
Basic	**$ (0.06)**	$ 0.07	$ 0.33	$ 0.88	$ (0.26)
Diluted	**$ (0.06)**	$ 0.07	$ 0.31	$ 0.79	$ (0.26)
Weighted average common stock and common stock equivalents outstanding					
Basic	**32,253**	25,323	21,264	20,680	20,458
Diluted	**32,253**	25,688	24,175	23,549	20,458
Cash dividends – common stock	**$ —**	$ —	$ —	$ —	$ —
Consolidated Balance Sheet Data:					
Total assets	**$ 253,008**	$ 170,671	$ 118,343	$ 102,351	$ 41,760
Total liabilities	**$ 163,506**	$ 110,677	$ 57,111	$ 56,852	$ 15,446
Long-term debt, less current maturities	**$ 100,000**	$ 79,000	$ 39,750	$ 45,604	$ 9,600
Total stockholders' equity	**$ 89,502**	$ 59,994	$ 61,232	$ 45,499	$ 26,314
Consolidated Statement of Cash Flow Data:					
Cash provided by (used in)					
Operating activities	**$ 37,118**	$ 18,156	$ 19,493	$ 1,528	$ 13,383
Investing activities	**$ (84,949)**	$ (69,518)	$ (15,494)	$ (30,277)	$ (11,357)
Financing activities	**$ 49,468**	$ 38,765	$ 1,567	$ 37,210	$ (676)
Operating Data:					
Product Sales					
Oil (Bbls)	**923**	729	629	131	138
Gas (Mcf)	**3,592**	2,690	3,356	2,670	3,266
BOE	**1,522**	1,177	1,188	576	682
Average sales price					
Oil (per Bbl)	**$ 51.78**	$ 39.05	$ 29.11	$ 24.59	$ 24.80
Gas (per Mcf)	**$ 8.54**	$ 5.85	$ 5.40	$ 3.33	$ 4.41
Proved reserves					
Oil (Bbls)	**22,091**	18,916	12,084	10,271	916
Gas (Mcf)	**25,417**	16,825	16,271	15,633	13,947

(1) Results include a $31.0 million gain attributable to equity in income of First Permian, L.P. Results also include noncash charges of $717,000 on the sale of stock we owned in Energen Corporation, $509,000 for the change in fair value of derivatives and $440,000 for the change in fair market value of our crude oil swaps.

(2) Results include noncash charges of $2.2 million in the fiscal quarter ended September 30, 2001 and $14.6 million in the fourth quarter ended December 31, 2001, in each case related to the impairment of oil and natural gas properties incurred in 2001 and primarily a result of a decrease in year-end reserves and lower oil and natural gas prices.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion is intended to assist you in understanding our financial position and results of operations for each year in the three-year period ended December 31, 2005. You should read the following discussion and analysis in conjunction with our consolidated financial statements and the related notes.

The following discussion contains forward-looking statements. For a description of limitations inherent in forward-looking statements, see "Cautionary Statement Regarding Forward Looking Statements" on page 3.

Overview and Strategy

Our primary objective is to increase stockholder value by increasing reserves, production, cash flow and earnings. We have shifted the balance of our investments from properties having high rates of production in early years to properties expected to produce more consistently over a longer term. We attempt to reduce our financial risks by dedicating a smaller portion of our capital to high risk projects, while reserving the majority of our available capital for acquisitions, exploitation and development drilling opportunities. Obtaining positions in long-lived oil and natural gas reserves are given priority over properties that might provide more cash flow in the early years of production, but which have shorter reserve lives. We also attempt to further reduce risk by emphasizing acquisition possibilities over high risk exploration projects.

During the latter part of 2002, we reduced our emphasis on high risk exploration efforts and started focusing on established geologic trends where we can utilize the engineering, operational, financial and technical expertise of our entire staff. Although we do participate in some exploratory drilling activities, reducing financial, reservoir, drilling and geological risks and diversifying our property portfolio are important criteria in the execution of our business plan. In summary, our current business plan:

- focuses on projects having less geological risk;
- emphasizes acquisition, exploitation, development and enhancement activities;
- includes the utilization of horizontal and fracture stimulation technologies on certain types of reservoirs;
- focuses on acquiring producing properties; and
- expands the scope of operations by diversifying our exploratory and development efforts, both in and outside of our current areas of operation.

Although the direction of our exploration and development activities has shifted from high risk exploratory activities to lower risk development opportunities, we will continue our efforts, as we have in the past, to maintain low general and administrative expenses relative to the size of our overall operations, utilize advanced technologies, serve as operator in appropriate circumstances, and reduce operating costs.

The extent to which we are able to implement and follow through with our business plan will be influenced by:

- the prices we receive for the oil and natural gas we produce;
- the results of reprocessing and reinterpreting our 3-D seismic data;
- the results of our drilling activities;
- the costs of obtaining high quality field services;
- our ability to find and consummate acquisition opportunities; and
- our ability to negotiate and enter into work to earn arrangements, joint venture or other similar agreements on terms acceptable to us.

Significant changes in the prices we receive for our oil and natural gas, or the occurrence of unanticipated events beyond our control may cause us to defer or deviate from our business plan, including the amounts we have budgeted for our activities.

Operating Performance

Our operating performance is influenced by several factors, the most significant of which are the prices we receive for our oil and natural gas and our productions volumes. The world price for oil has overall influence on the prices that we receive for our oil production. The prices received for different grades of oil are based upon the world price for oil, which is then adjusted based upon the particular grade. Typically, light oil is sold at a premium, while heavy grades of crude are discounted. Natural gas prices we receive are influenced by:

- seasonal demand;
- weather;
- hurricane conditions in the Gulf of Mexico;
- availability of pipeline transportation to end users;
- proximity of our wells to major transportation pipeline infrastructures; and
- world oil prices.

Additional factors influencing our overall operating performance include:

- production expenses;
- overhead requirements; and
- costs of capital.

Our oil and natural gas exploration, development and acquisition activities require substantial and continuing capital expenditures. Historically, the sources of financing to fund our capital expenditures have included:

- cash flow from operations;
- sales of our equity securities;
- bank borrowings; and
- industry joint ventures.

Depletion per BOE in 2005 was $7.61 versus $7.05 in 2004 and $ 6.83 in 2003. The increase per BOE in 2005 was a result of increased drilling costs and acquisitions of producing properties.

Our oil and natural gas producing activities are accounted for using the full cost method of accounting. Under this accounting method, we capitalize all costs incurred in connection with the acquisition of oil and natural gas properties and the exploration for and development of oil and natural gas reserves. See Note 3 to the consolidated financial statements. These costs include lease acquisition costs, geological and geophysical expenditures, costs of drilling productive and non-productive wells, and overhead expenses directly related to land and property acquisition and exploration and development activities. Proceeds from the disposition of oil and natural gas properties are accounted for as a reduction in capitalized costs, with no gain or loss recognized unless a disposition involves a material change in reserves, in which case the gain or loss is recognized.

Depletion of the capitalized costs of oil and natural gas properties, including estimated future development costs, is provided using the equivalent unit-of-production method based upon estimates of proved oil and natural gas reserves and production, which are converted to a common unit of measure based upon their relative energy content. Unproved oil and natural gas properties are not amortized, but are individually assessed for impairment. The cost of any impaired property is transferred to the balance of oil and natural gas properties being depleted.

Results of Operations

As described under "Item 1. Business – About Our Strategy and Business", we changed our business model in 2002. At the beginning of 2002, our reserves were approximately 3.2 MMBoe with a reserves to production ratio of approximately 4 to 1. Through the execution of this business model, our reserves at the end of 2005 were approximately 25.4 MMBoe with a reserves to production ratio of approximately 16.7 to 1. As described on page 21 of this report, the failure to replace oil and gas reserves may negatively affect our business. We monitor this risk by comparing the quantity of our oil and natural gas reserves at the end of each year to our production for that year. This comparison, which is made in the form of a reserves to production ratio, helps us measure our ability to offset produced volumes with new reserves that will be produced in the future. The reserves to production ratio is calculated by dividing the total proved reserves at the end of a year by the actual production for the same year. The ratio provides us with an indication of our performance in replenishing annual production volumes. The reserves to production ratio is a statistical indicator that has limitations. The ratio is limited because it can vary widely based on the extent and timing of new discoveries and property acquisition. In addition, the ratio does not take into account the cost or timing of future production of new reserves. For that reason, the ratio does not, and is not intended to, provide a measurement of value. At the end of 2002, our production was 77% natural gas and 23% oil, as compared to 39% natural gas and 61% oil at the end of 2005. The production stream changed from short life gulf coast natural gas to long life Permian Basin oil production and has increased our lease operating expense primarily due to increased utilities and chemicals associated with the oil properties.

The following table shows selected data and operating income comparisons for each of the three years ended December 31, 2005.

Years ended December 31, (in thousands except per unit data)	**2005**	2004	2003
Production Volumes			
Oil (Bbls)	**923**	729	629
Natural gas (Mcf)	**3,592**	2,690	3,356
BOE	**1,522**	1,177	1,188
Sales Price			
Oil (per Bbl)(1)	**$ 51.78**	$ 39.05	$ 29.11
Natural gas (per Mcf)(1)	**$ 8.54**	$ 5.85	$ 5.40
BOE Price(1)	**$ 51.57**	$ 37.55	$ 30.66
BOE Price(2)	**$ 43.46**	$ 30.45	$ 28.50
Operating Revenues			
Oil	**$ 47,800**	$ 28,455	$ 18,300
Effect of oil hedges	**(12,139)**	(7,458)	(1,659)
Natural gas	**30,690**	15,735	18,121
Effect of natural gas hedges	**(201)**	(895)	(907)
	66,150	35,837	33,855
Operating Expenses			
Lease operating expense	**9,947**	7,373	6,458
Production taxes	**4,102**	2,108	1,946
General and administrative:			
General and administrative	**4,289**	3,123	3,019
Public reporting	**2,423**	2,255	1,325
Depreciation and depletion	**12,044**	8,712	8,390
	32,805	23,571	21,138
Operating income	**$ 33,345**	$ 12,266	$ 12,717

(1) Excludes hedge transactions.
(2) Includes hedge transactions.

Critical Accounting Policies and Practices

Full Cost and Impairment of Assets. We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized. Costs of non-producing properties, wells in process of being drilled and significant development projects are excluded from depletion until such time as the related project is developed and proved reserves are established or impairment is determined. At the end of each quarter, the net capitalized costs of our oil and natural gas properties, as adjusted for asset retirement obligations, is limited to the lower of unamortized cost or a ceiling, based on the present value of estimated future net revenues, net of income tax effects, discounted at 10%, plus the lower of cost or fair market value of our unproved properties. Revenues are measured at unescalated oil and natural gas prices at the end of each quarter, with effect given to our cash flow hedge positions. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are subject to a ceiling test write-down to the extent of the excess. A ceiling test write-down is a non-cash charge to earnings. It reduces earnings and impacts stockholders' equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods.

There is a risk that we will be required to write down the carrying value of oil and natural gas properties increases when oil and natural gas prices decline. If commodity prices deteriorate, it is possible that we could incur an impairment in future periods.

Depletion. Provision for depletion of oil and natural gas properties under the full cost method is calculated using the unit of production method based upon estimates of proved oil and natural gas reserves with oil and natural gas production being converted to a common unit of measure based upon their relative energy content. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. Oil and natural gas properties included $19.9 million and $9.5 million for 2005 and 2004, respectively, for unproved properties not included in depletion. The cost of any impaired property is transferred to the balance of oil and natural gas properties being depleted.

Proved Reserve Estimates. Our discounted present value of proved oil and natural gas reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. Our reserve estimates are prepared by independent petroleum engineers.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost ceiling write-down. At December 31, 2005, the excess of the ceiling over our capitalized costs was over $200.0 million. In addition to the impact of these estimates of proved reserves on calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of depreciation, depletion and amortization.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. Accounting principles generally accepted in the United States require that prices and costs in effect as of the last day of the period are held constant indefinitely. Accordingly, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than prices we actually receive in the long-term, which are a barometer for true fair value.

Use of Estimates. The preparation of consolidated financial statements in accordance with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect reported assets, liabilities, expenses, and some narrative disclosures. Hydrocarbon reserves, future development costs and certain hydrocarbon production expenses are the most critical estimates to our consolidated financial statements.

Derivatives. The Financial Accounting Standards Board issued SFAS No. 133, as amended by SFAS No. 138, that requires all derivative instruments be recorded on the balance sheet at their respective fair values. We adopted SFAS no. 133 on January 1, 2001.

For the period from January 1, 2003 to June 30, 2004, derivative contracts were designated as cash flow hedges. These contracts have remained designated as cash flow hedges through December 31, 2005. Accordingly, the effective portion of the unrealized gains or losses has been recorded in other comprehensive loss until the settlement of the contract position occurs. At settlement of these contracts, the cash value paid is recorded in revenue along with the oil and gas sales or in interest expense along with our interest expense that we incurred with our credit facility agreements.

For periods prior to 2003 and for periods after July 1, 2004, derivative contracts entered into were not designated as cash flow hedges. Accordingly, the unrealized gain or loss on these derivative contracts was recorded in other income.

At settlement of these contracts, the settlement value will remain in other income and will not be offset against the oil and gas sales revenue or in interest expense.

Although we have designated our derivative contracts differently in different periods, the purpose of all of our derivative contracts is to provide a measure of stability in our oil and natural gas receipts and interest rate payments and to manage exposure to commodity price and interest rate risk under existing sales contracts.

Years Ended December 31, 2005 and December 31, 2004

Our oil and natural gas revenues and production product mix are displayed in the following table for the years ended December 31, 2005 and 2004.

Oil and Gas Revenues

	Revenues(1)		Production	
	2005	2004	**2005**	2004
		(restated)		
Oil (Bbls)	**54%**	59%	**61%**	62%
Natural gas (Mcf)	**46%**	41%	**39%**	38%
Total	**100%**	100%	**100%**	100%

(1) Includes the effects of derivative transactions accounted for as hedges. See ("Financial Statement Restatement" and Note 18 to the Consolidated Financial Statements.

The following table outlines the detail of our operating revenues for the following periods.

(in thousands except per unit data)	Year Ended December 31, **2005**	Year Ended December 31, 2004	Increase (Decrease)	% Increase (Decrease)
Production Volumes				
Oil (Bbls)	**923**	729	194	27%
Natural gas (Mcf)	**3,592**	2,690	902	34%
BOE	**1,522**	1,177	345	29%
Sales Price				
Oil (per Bbl)(1)	**$ 51.78**	$ 39.05	$ 12.73	33%
Natural gas (per Mcf)(1)	**$ 8.54**	$ 5.85	$ 2.69	46%
BOE price(1)	**$ 51.57**	$ 37.55	$ 14.02	37%
BOE price(2)	**$ 43.46**	$ 30.45	$ 13.01	43%
Operating Revenues				
Oil	**$ 47,800**	$ 28,455	$ 19,345	68%
Effect of oil hedges	**(12,139)**	(7,458)	4,681	63%
Natural gas	**30,690**	15,735	14,955	95%
Effect of natural gas hedges	**(201)**	(895)	(694)	(78)%
Total	**$ 66,150**	$ 35,837	$ 30,313	85%

(1) Excludes hedge transactions.
(2) Includes hedge transactions.

Oil revenues, excluding hedges, increased $19.3 million or 68% for the year ended 2005 compared to 2004. Oil production volumes increased 27%, which was attributable to our 2005 drilling program in the Carm-Ann San Andres Field/N. Mean Queen Field acquired in 2004 and early 2005, re-stimulations and new drills in the Fullerton San Andres Field and our drilling program in the Diamond M Canyon Reef. The increase in oil production increased revenue approximately $10.0 million for 2005. Wellhead average realized crude oil prices increased $12.73 per Bbl or 33% to $51.78 per Bbl for 2005 compared to 2004. The increase in oil price increased revenue approximately $9.3 million for 2005.

Natural gas revenues, excluding hedges, increased $15.0 million or 95% for the year ended 2005 compared to 2004. Natural gas production volumes increased 34% due to production from drilling discoveries in our south Texas Wilcox wells and initial production from our Fort Worth Basin Barnett Shale wells. The increase in natural gas volumes increased revenue approximately $7.7 million for 2005. Average realized wellhead natural gas prices increased 46% or $2.69 per Mcf to $8.54 per Mcf. The increase in natural gas prices had a positive effect on revenues of approximately $7.3 million for the period ending 2005.

The negative effect on oil revenues of oil hedges increased $4.7 million or 63% for 2005 compared to 2004 due to the increase in oil prices. The negative effect on natural gas revenues of natural gas hedge losses was $201,000 in 2005, as compared to $895,000 in 2004. Although natural gas prices increased 78% in 2005, we had less natural gas volumes hedged for 2005. On a BOE basis, hedges accounted for a reduction in revenue of $8.11 per BOE in 2005 compared to $7.10 per BOE in 2004.

Costs and Expenses

	Year Ended December 31,		Increase	% Increase
(dollars in thousands)	2005	2004	(Decrease)	(Decrease)
Lease operating expense	$ 9,947	$ 7,373	$2,574	35%
Production taxes	4,102	2,108	1,994	95%
General and administrative:				
General and administrative	4,289	3,123	1,166	37%
Public reporting	2,423	2,255	168	7%
Total general and administrative	6,712	5,378	1,334	25%
Depreciation and depletion	12,044	8,712	3,332	38%
Total	$ 32,805	$ 23,571	9,234	39%

Lease operating expense increased 35% or $2.6 million compared to 2004. 61% of our 2005 production is long-life oil assets which are in the west Texas Fullerton, Carm-Ann, newly acquired Harris properties and work-to-earn agreement at Diamond M. Our increase in lease operating expenses is due to mechanical, ad valorem and utility costs thereby our related lifting costs were $9.29 per BOE in 2005 compared to $8.06 per BOE in 2004. We experienced a 15% increase in our per BOE lifting costs primarily due to higher lifting costs associated with operating new wells and newly acquired wells for the year ended December 31, 2005. As we continue to exploit and develop our long-life Permian Basin oil properties (Fullerton, Carm-Ann, Harris and Diamond M), and if our production increases as we expect, we also expect that our lifting costs will continue around the same level or decline due to efficiencies gained by increased activity. The lifting costs are also expected to be reduced by the development of natural gas properties in south Texas, Barnett Shale and Permian Basin of New Mexico.

Production taxes increased 95% or $2.0 million in 2005, associated with a net wellhead increase in revenues of $34.3 million. Production taxes in future periods will continue to be a function of product mix, production volumes and product prices.

General and administrative expenses in total increased 25% or $1.3 million in 2005 compared to 2004. General and administrative expenses increased with our aggressive drilling program in 2005 through employee additions, bonus payments, benefits, and public reporting costs. General and administrative expenses capitalized to the full cost pool were $1.3 million for 2005 compared to $1.1 million for 2004. On a BOE basis, general and administrative costs were $2.82 per BOE in 2005 compared to $2.65 per BOE in 2004, while public reporting costs were $1.59 per BOE and $1.92 per BOE for the same period. General and administrative expenses will increase in 2006 in association with reporting requirements and operational support of current and new acquisitions.

Depreciation and depletion expense increased 38% or $3.3 million for 2005 compared to 2004. Depletion per BOE was $7.61 for 2005 and $7.05 for 2004. This increase is attributable to property purchases and increased drilling costs. Depreciation expense increased with the cost of a new accounting and production system in 2004. Depletion costs are highly correlated with production volumes and capital expenditures. Fiscal year 2006 depletion costs will increase with increased production volumes.

Other income (expense)

(dollars in thousands)	Year Ended December 31, 2005	2004	Increase (Decrease)	% Increase (Decrease)
		(restated)		
Change in fair market value of derivative instruments	**$ (31,669)**	$ (5,726)	$ 25,943	453%
Gain (loss) on ineffective portion of hedges	**(137)**	(240)	(103)	(43)%
Interest and other income	**167**	189	(22)	(12)%
Interest expense	**(4,780)**	(2,732)	2,048	75%
Other expense	**(191)**	(324)	(133)	(41)%
Total	**$ (36,610)**	$ (8,833)	$ 27,777	314%

Beginning in the third quarter of 2004, no derivative contracts initiated were designated as cash flow hedges as defined by SFAS 133. None of the derivative contracts that were entered into 2004 settled in 2004.

We recorded a loss of $31.7 million in 2005 for the change in fair value of derivatives in 2005, as compared to a loss of $5.7 million for 2004. The increase is partly attributable to derivative contracts being designated as cash flow hedges prior to 2004 and beginning in 2004 we did not designate these types of contract as cash flow hedges. As a result, changes in the fair value of these contracts were recorded in this account. The loss also increased because of large increases in commodity prices for oil contracts. Future gains or losses on changes in derivatives will be impacted by the volatility of commodity prices and interest rates, as well as the terms of any new derivative contracts.

The loss associated with the ineffective portion of our hedges decreased $103,000 or 43% for 2005 compared to 2004. Commodity prices increased in 2005, resulting in an ineffective portion to be recorded in other expense. The ineffective hedge gain or loss may increase or decrease until settlement of our contracts. As of December 31, 2005, we have only one remaining commodity contract and one remaining interest rate swap contract designated as cash flow hedges as defined by SFAS 133.

Interest expense increased with the increase of debt from $79.0 million to $100.0 million in 2005 along with an increase of our average loan interest rate from 7.01% to 7.96% later in 2005. Other expenses decreased in 2005 associated with legal, accounting and related costs associated with an aborted high yield debt offering in 2004. Interest expense will increase for 2006 with increased borrowings due to our acquisitions, potential interest rate increases and our increased drilling budget.

We had an income tax benefit of $1.7 million in 2005 compared to a $1.2 million expense in 2004. The income tax rate for 2006 will be dependent on our earnings and is expected to be approximately 35% of income before income taxes.

We had basic and diluted net loss per share of $.06 for 2005 and basic and diluted net earnings per share of $.07 for 2004. Basic weighted average common shares outstanding increased from 25.3 million shares in 2004 to 32.3 million shares in 2005. Diluted weighted average common shares increased from 25.7 million shares in 2004 to 32.3 million shares in 2005. The increase in common shares is due to the common stock offering of 5.75 million shares in February, 2005, and the conversion of the Preferred Stock in June, 2005, for 2.7 million shares of common stock.

Years Ended December 31, 2004 and December 31, 2003

Our oil and natural gas revenues and production product mix are displayed in the following table for the years ended December 31, 2004 and 2003.

Oil and Gas Revenues

	Revenues[1]		Production	
	2004	2003	2004	2003
Oil (Bbls)	59%	49%	62%	53%
Natural gas (Mcf)	41%	51%	38%	47%
Total	100%	100%	100%	100%

(1) Includes hedge transactions

The following table outlines the detail of our operating revenues for the following periods.

(in thousands except per unit data)	Year Ended December 31, 2004	2003	Increase (Decrease)	% Increase (Decrease)
Production Volumes				
Oil (Bbls)	729	629	100	16%
Natural gas (Mcf)	2,690	3,356	(666)	(20)%
BOE	1,177	1,188	(11)	(1)%
Sales Price				
Oil (per Bbl)[1]	$ 39.05	$ 29.11	$ 9.94	34%
Natural gas (per Mcf)[1]	$ 5.85	$ 5.40	$ 0.45	8%
BOE price[1]	$ 37.55	$ 30.66	$ 6.89	22%
BOE price[2]	$ 30.45	$ 28.50	$1.95	7%
Operating Revenues				
Oil	$ 28,455	$ 18,300	$ 10,155	55%
Effect of oil hedges	$ (7,458)	$ (1,659)	$ 5,799	350%
Natural gas	$ 15,735	$ 18,121	$ (2,386)	(13)%
Effect of natural gas hedges	$ (895)	$ (907)	$ (12)	(1)%
Total	$ 35,837	$ 33,855	$ 1,982	6%

(1) Excludes hedge transactions.
(2) Includes hedge transactions.

Oil revenues, excluding hedges, increased $10.2 million or 55% for the year ended 2004 compared to 2003. Oil production volumes increased 16% attributable to re-stimulations and additional acquisitions in the Fullerton San Andres Field, acquisitions in the Carm-Ann San Andres Field/N. Means Queen Unit and the drilling of producing and injection wells on our Diamond M Property. The increase in oil production increased revenue approximately $3.9 million for 2004. Wellhead average realized crude oil prices increased $9.94 per Bbl or 34% to $39.05 per Bbl for 2004 compared to 2003. The increase in oil price increased revenue approximately $6.3 million for 2004.

Natural gas revenues, excluding hedges, decreased $2.4 million or 13% for the year ended 2004 compared to 2003. Natural gas production volumes decreased 20% due to natural production declines in our south Texas Yegua/Frio and Cook Mountain projects. The decline in natural gas volumes decreased revenue approximately $3.6 million for 2004. Average realized wellhead natural gas prices increased 8% or $0.45 per Mcf to $5.85 per Mcf. The increase in natural gas prices had a positive effect on revenues of approximately $1.2 million for the period ending 2004.

Losses on oil hedges increased $5.8 million or 350% for 2004 compared to 2003 due to the increase in oil prices. Natural gas hedge losses were $895,000 in 2004 compared to $907,000 in 2003. Although natural gas prices increased 8% in 2004, we had less natural gas volumes hedged for 2004. On a BOE basis, hedges accounted for a realized loss of $7.10 per BOE in 2004 compared to $2.16 per BOE in 2003.

Cost and Expenses

(dollars in thousands)	Year Ended December 31, 2004	2003	Increase (Decrease)	% Increase (Decrease)
Lease operating expense	$ 7,373	$ 6,458	$ 915	14%
Production taxes	2,108	1,946	162	8%
General and administrative:				
General and administrative	3,123	3,019	104	3%
Public reporting	2,255	1,325	930	70%
Total general and administrative	5,378	4,344	1,034	24%
Depreciation and depletion	8,712	8,390	322	4%
Total	$ 23,571	$ 21,138	$ 2,433	12%

Lease operating expense increased 14% or $915,000 compared to 2003. During 2004, 62% of our production was crude oil compared to 53% in 2003. The change in our business plan to long-life assets which influenced our purchase of assets in the west Texas Fullerton, Carm-Ann and work-to-earn agreement at Diamond M has shifted our production and reserves away from a natural gas base to a crude oil base. This shift has increased the lease operating expense due to the mechanical operations and utilities required to produce oil properties compared to natural gas properties. Lifting costs were $8.06 per BOE in 2004 compared to $7.07 per BOE in 2003 on a BOE basis. Production taxes increased 8% or $162,000 in 2004, associated with a net wellhead increase in revenues of $7.8 million.

General and administrative in total increased 24% or $1.0 million in 2004 compared to 2003. Included in our total general and administrative costs is public reporting cost which increased 70% or $930,000 for 2004. The increase in public reporting cost was attributable to audit costs associated with the change of auditors at the end of 2003 and increased legal costs and costs attributable to the work on our internal control over financial reporting under Section 202 of the Sarbanes-Oxley Act of 2002 or "SOX 404". General and administrative expenses capitalized to the full cost pool were $1.1 million for 2004 compared to $900,000 for 2003. On a BOE basis, general and administrative costs were $2.65 per BOE in 2004 compared to $2.54 per BOE in 2003, while public reporting costs were $1.92 per BOE and $1.12 per BOE for the same period.

Depreciation and depletion expense increased 4% or $322,000 for 2004 compared to 2003. Depletion per BOE was $7.05 for 2004 and $6.83 for 2003. This increase is attributable to increased drilling costs and producing property purchases.

Depreciation expense increased with the cost of a new accounting and production system in 2004.

Other income (expense)

	Year Ended December 31,		Increase	% Increase
(dollars in thousands)	2004	2003	(Decrease)	(Decrease)
	(restated)			
Change in fair market value of derivative instruments	$ (5,726)	$ (22)	$ 5,704	25,927%
Gain (loss) on ineffective portion of hedges	(240)	191	(431)	(226)%
Interest and other income	189	116	73	63%
Interest expense	(2,732)	(2,048)	684	33%
Other expense	(324)	(259)	65	25%
Total	$ (8,833)	$ (2,022)	$ 6,811	337%

We recorded a loss of $5.7 million for the change in fair value of derivatives for 2004. The loss is partly attributable to derivative contracts being designated as cash flow hedges prior to 2004 and beginning in 2004 we did not designate these types of contract as cash flow hedges. As a result, changes in the fair value of these contracts were recorded in this account. The loss resulted from large increases in commodity prices for oil after we entered into our 2004 derivate contracts.

The loss associated with the ineffective portion of our hedges increased $431,000 or 226% for 2004 compared to 2003. Basis differential between NYMEX WTI and the average price we received on volumes we hedged increased in 2004 as compared to prices in 2003, and resulted in an ineffective portion to be recorded for our hedge positions we put in place during 2003 and 2002. We did not enter into a cash flow hedge as defined by SFAS 133 subsequent to June 30, 2004.

Interest and other income increased with increased interest income and other non-recurring income. Interest expense increased with the increase of debt from approximately $40.0 million to $79.0 million in 2004 along with an increase of our loan interest rate from 4.50% to 7.25% later in 2004. Other expenses increased in 2004 associated with legal, accounting and related costs associated with an aborted high yield debt offering. Income tax expense was $1.2 million in 2004 compared to $3.0 million in 2003. 2003 included a reduction of $900,000 for state income tax. We had basic net earnings per share of $.07 and $.33 and diluted earnings per share of $.07 and $.31 for 2004 and 2003, respectively. Basic weighted average common shares outstanding increased from 21.3 million shares in 2003 to 25.3 million shares in 2004. Diluted weighted average common shares increased from 24.2 million shares in 2003 to 25.7 million shares in 2004. The increase in common shares is due to the private placement of 4.0 million shares in late December 2003 and stock options exercised in 2004.

Capital Resources and Liquidity

Our capital resources consist primarily of cash flows from our oil and natural gas properties, bank borrowings supported by our oil and natural gas reserve sales of non-strategic properties and equity offerings. Our level of earnings and cash flows depends on many factors, including the prices we receive for oil and natural gas we produce.

Working capital decreased 49% or $413,000 as of December 31, 2005 compared with December 31, 2004. Current assets exceeded current liabilities by $433,000 at December 31, 2005. The major working capital decrease was associated with increased derivative obligations as a result of the increase in oil and natural gas prices.

The following table summarizes our cash flow from operating, investing and financing activities:

Year ended December 31, (in thousands)	**2005**	2004	2003
Operating activities	**$ 37,118**	$ 18,156	$ 19,493
Investing activities	**$ (84,949)**	$ (69,518)	$ (15,494)
Financing activities	**$ 49,468**	$ 38,765	$ 1,567

Cash provided from operating activities in 2005 increased $19.0 million over 2004 largely due to increased operating income from our increased capital projects the Carm-Ann acquisition, new production in the Wilcox Gas project and increased sales prices in 2005.

Cash used in investing activities increased in 2005 compared to 2004 primarily as a result of the Harris acquisition and our increased drilling for 2005.

Cash provided by financing activities increased in relationship due to borrowings to fund our acquisition and increased drilling offset by our equity offering in February 2005. Proceeds from the equity offering were utilized in reducing our debt.

We had additions to oil and gas properties of $77.4 million for the year ended December 31, 2005, which were primarily due to our property acquisitions of $22.3 million, leasehold acquisition, development, and enhancement activities. Also added to our property basis were asset retirement costs of $251,000 (see Note 5). The property acquisitions, development and enhancement activities were financed by the utilization of cash flows provided by operations and our credit facility.

As of March 1, 2006 the amount available under our universal shelf registration statement filed with the Securities of Exchange Commission for the offer and sale, from time to time, of our debt and equity securities totaled approximately $69.7 million.

Based on our projected oil and natural gas revenues and related expenses and available bank borrowings, we believe that we will have sufficient capital resources to fund normal operations and capital requirements, interest expense and principal reduction payments on bank debt, if required. We continually review and consider alternative methods of funding.

Credit Facilities

We have two separate credit facilities. Our Third Amended and Restated Credit Agreement (or the "Revolving Credit Agreement"), dated as of December 23, 2005, with a group of bank lenders provides a revolving line of credit having a "borrowing base limitation" of $125.0 million at December 31, 2005. The total amount that we can borrow and have outstanding at any one time is limited to the lesser of $350.0 million or the borrowing base established by the lenders. At December 31, 2005, the principal amount outstanding under our revolving credit facility was $50.0 million, excluding $490,000 reserved for our letters of credit. The second credit facility is a five year term loan facility provided to us under a Second Lien Term Loan Agreement (the "Second Lien Agreement"), dated as of November 15, 2005, with a group of banks and other lenders. At December 31, 2005, our term loan under this facility was fully funded in the principal amount of $50.0 million, which was outstanding on that same date.

Revolving Credit Facility

The Revolving Credit Agreement provides for a credit facility that allows us to borrow, repay and reborrow amounts available under the revolving credit facility. The amount of the borrowing base is based primarily upon the estimated value of our oil and natural gas reserves. The borrowing base amount is redetermined by the lenders semi-annually on or about April 1 and October 1 of each year or at other times required by the lenders or at our request. If, as a result of the lenders' redetermination of the borrowing base, the outstanding principal amount of our loans exceeds the borrowing base, we must either provide additional collateral to the lenders or repay the outstanding principal of our loans in an amount equal to the excess. Except for the principal payments that may be required because of our outstanding loans being in excess of the borrowing base, interest only is payable monthly.

Loans made to us under this revolving credit facility bear interest at the base rate of Citibank, N.A. or the LIBOR rate, at our election. Generally, Citibank's base rate is equal to its "prime rate" as announced from time to time by Citibank.

The LIBOR rate is generally equal to the sum of (a) the rate designated as "British Bankers Association Interest Settlement Rates" and offered on one, two, three, six or twelve month interest periods for deposits of $1.0 million, and (b) a margin ranging from 2.00% to 2.50%, depending upon the outstanding principal amount of the loans. If the principal amount outstanding is equal to or greater than 75% of the borrowing base, the margin is 2.50%. If the principal amount outstanding is equal to or greater than 50%, but less than 75% of the borrowing base, the margin is 2.25%. If the principal amount outstanding is less than 50% of the borrowing base, the margin is 2.00%.

The interest rate we are required to pay on our borrowings, including the applicable margin, may never be less than 5.00%. At December 31, 2005, our Libor interest rate, plus margin, was 6.40% on $50.0 million.

In the case of base rate loans, interest is payable on the last day of each month. In the case of LIBOR loans, interest is payable on the last day of each applicable interest period.

If the total outstanding borrowings under the revolving credit facility are less than the borrowing base, an unused commitment fee is required to be paid to the lenders. The amount of the fee is .25% of the daily average of the unadvanced amount of the borrowing base. The fee is payable quarterly.

If the borrowing base is increased, we are required to pay a fee of .375% on the amount of any increase in the borrowing base.

All outstanding principal under the revolving credit facility is due and payable on October 31, 2010. The maturity date of our outstanding loans may be accelerated by the lenders upon the occurrence of an event of default under the Revolving Credit Agreement.

The Revolving Credit Facility contains various restrictive financial covenants and compliance requirements. As a result of financial statement errors concerning our accounting for certain oil and natural gas and interest rate derivative instruments, we were not in compliance with certain covenants concerning financial reporting. We have obtained waivers of these covenants from our lenders. We were in compliance with the remainder of the covenants in our revolving credit facility. See note 18 to the consolidated financial statements. The revolving credit facility also contains restrictions on all retained earnings and net income for payment of dividends on common stock.

Second Lien Term Loan Facility

The Second Lien Agreement provides a $50.0 million term loan. Loans made to us under this credit facility bear interest at an alternate base rate or the LIBOR rate, at our election. The alternate base rate is the greater of (a) the prime rate in effect on such day and (b) the "Federal Funds Effective Rate" in effect on such day plus ½ of 1%, plus a margin of 3.50% per annum.

The LIBOR rate is generally equal to the sum of a (a) the rate designated as "British Bankers Association Interest Settlement Rates" and offered on one, two, three or six month interest periods for deposits of $1.0 million and (b) an applicable margin rate per annum equal to 4.50%.

At December 31, 2005, our Libor interest rate, plus the applicable margin, was 9.0% on $50.0 million.

In the case of alternate base rate loans, interest is payable the last day of each March, June, September and December. In the case of LIBOR loans, interest is payable the last day of the tranche period not to exceed a three month period.

All outstanding principal under the Second Lien Agreement is due and payable on November 15, 2010. The maturity date may be accelerated by the lenders upon the occurrence of an event of default under the Second Lien Agreement.

Prepayments in whole or in part if made prior to the first anniversary date will bear a premium of 1% of the amount prepaid. There is no premium after the first anniversary date.

The Second Lien Agreement contains various restrictive financial covenants and compliance requirements. As a result of financial statement errors concerning our accounting for certain oil and natural gas and interest rate derivative instruments, we were not in compliance with certain covenants concerning financial reporting. We have obtained waivers of these covenants from our lenders. We were in compliance with the remainder of the covenants in the second lien term loan facility. See note 18 to the Consolidated Financial Statements.

Preferred Stock

At December 31, 2004 we had 950,000 shares of 6% convertible preferred stock outstanding. The preferred stock:

- required us to pay dividends of $.60 per annum, semi-annually on June 15 and December 15 of each year;
- was convertible into common stock at any time, at the option of the holder, into 2.8751 shares of common stock at an initial conversion price of $3.50 per share, subject to adjustment in certain events;
- was redeemable at our option, in whole in part, for $10 per share, plus accrued dividends;
- had no voting rights, except as required by applicable law, and except that as long as any shares of preferred stock remain outstanding, the holders of a majority of the outstanding shares of the preferred stock may vote on any proposal to change any provision of the preferred stock which materially and adversely affects the rights, preferences or privileges of the preferred stock;
- was senior to the common stock with respect to dividends and on liquidation, dissolution or winding up of Parallel;
- had a liquidation value of $10 per share, plus accrued and unpaid dividends.

As of June 6, 2005, all 950,000 outstanding shares of 6% convertible preferred stock had been converted into 2,714,280 shares of common stock.

Commodity Price Risk Management Transactions and Effects of Derivative Instruments

The purpose of all of our derivative trades is to provide a measure of stability in cash flow as a result of our daily activities associated with the selling of oil and gas production and expenditures associated with borrowings that we have secured through our credit Facilities. The derivative trade arrangements we have employed include collars, costless collars, floors or purchased puts, oil and natural gas and interest rate swaps. In 2003, we designated our derivative trades as cash flow hedges under the provisions of SFAS 133, as amended. Although our purpose for entering into derivative trades has remained the same, contracts entered into after June 30, 2004 were not designated as cash flow hedges.

Under cash flow hedge accounting for oil and natural gas production, the quarterly effective portion of the change in fair value of the commodity derivatives is recorded in stockholders' equity as other comprehensive income (loss) and then transferred to revenue in the period the related oil and gas production is sold. Ineffective portions of cash flow hedges (changes in the fair value of derivative instruments due to changes in realized prices that do not match the changes in the hedge price) are recognized in other expenses as they occur. While the cash flow hedge contract is open, the ineffective gain or loss may increase or decrease until settlement of the contract. As of December 31, 2005, we had 750 Bbls per day of our anticipated production through December 20, 2006 designated as cash flow hedges. All other commodity derivative trades are accounted for by "mark-to-market" accounting whereby changes in fair value are charged to earnings. Changes in the fair values of derivatives are recorded in our Consolidated Statements of Operations as these changes occur in the "Other income (expense), net" section of this statement. To the extent these trades relate to production in 2006 and beyond and oil prices increase, we report a loss currently, but if there is no further change in prices, our revenue will be correspondingly higher (than if there had been no price increase) when the production is sold.

Under cash flow hedge accounting for interest rates, the quarterly change in the fair value of the derivative is recorded in stockholders' equity as other comprehensive income (loss). The gain or loss is transferred, on a contract by contract basis, to interest expense as the interest accrues. Ineffective portions of cash flow hedges are recognized in other expense as they occur. As of December 31, 2005, floating rate interest on only $10 million of borrowings under our Revolving Credit Agreement was hedged for 2006. All other interest rate swaps that we have entered into for 2006 and beyond are accounted for by "mark-to-market" accounting as prescribed in SFAS 133.

We are exposed to credit risk in the event of nonperformance by the counterparties in our derivative trade instruments. However, we periodically assess the creditworthiness of the counterparties to mitigate this credit risk.

For additional information about our price risk management transactions, see Item 7A of this Annual Report on Form 10-K, beginning on page 51.

Future Capital Requirements

Our capital expenditure budget for 2006 is approximately $103.7 million and is highly dependent on future oil and natural gas prices and the availability of funding. These expenditures will be governed by the following factors:

- internally generated cash flows;
- availability of borrowing under our revolving credit facility;
- availability supply and services;
- additional sources of funding; and
- future drilling successes.

In 2006, we anticipate spending $66.6 million, or 64% of our capital investment budget on two horizontal drilling gas projects, the New Mexico Wolfcamp and the Barnett Shale projects. We also plan to spend $28.6 million, or 28% of the budget, on long-life, shallow oil properties located in the Permian Basin of west Texas.

Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

We have contractual obligations and commitments that may affect our financial position. The following table is a summary of significant contractual obligations:

	Obligation Due in Period						
Contractual Cash Obligations	2006	2007	2008	2009	2010	After 5 years	Total
				(in thousands)			
Revolving Credit Facility (secured)	$ —	$ —	$ —	$ —	$ 50,000	$ —	$ 50,000
Second Lien Term Loan Agreement	—	—	—	—	50,000	—	50,000
Office Lease (Dinero Plaza)	193	204	210	216	36	—	859
Andrews and Snyder Field Offices(1)	23	23	14	14	14	(1)	88
Asset Retirement Obligations(2)	214	28	35	101	254	1,863	2,495
Derivative Obligations	16,607	13,471	11,852	112	92	—	42,134
Total	$ 17,037	$ 13,726	$ 12,111	$ 443	$ 100,396	$ 1,863	$ 145,576

(1) The Snyder field office lease remains in effect until the termination of our trade agreement with a third party working interest owner in the Diamond "M" project. The Andrews field office lease expires in December 2007. The lease cost for these two office facilities are billed to nonaffiliated third party working interest owners under our joint operating agreements with these third parties.

(2) Asset retirement obligations of oil and natural gas assets, excluding salvage value and accretion.

Deferred taxes are not included in the table above. The utilization of net operating loss carryforwards combined with our plans for development and acquisitions may offset any major cash outflows. However, the ultimate timing of the settlements cannot be precisely determined.

In addition to our principal payment obligations under the revolving credit facility and second lien term loan facility noted in the table above, we are subject to interest payments on such indebtedness. See Note 8 to the consolidated financial statements.

We have no off-balance sheet financing arrangements or any unconsolidated special purpose entities.

Outlook

The oil and natural gas industry is capital intensive. We make, and anticipate that we will continue to make, substantial capital expenditures in the exploration for, development and acquisition of oil and natural gas reserves. Historically, our capital expenditures have been financed primarily with:

- internally generated cash from operations;
- proceeds from bank borrowings; and
- proceeds from sales of equity securities.

The continued availability of these capital sources depends upon a number of variables, including:

- our proved reserves;
- the volumes of oil and natural gas we produce from existing wells;
- the prices at which we sell oil and natural gas; and
- our ability to acquire, locate and produce new reserves.

Each of these variables materially affects our borrowing capacity. We may from time to time seek additional financing in the form of:

- increased bank borrowings;
- sales of Parallel's securities;
- sales of non-core properties; or
- other forms of financing.

We do not have agreements for any future financing and there can be no assurance as to the availability or terms of any such financing.

Inflation

Our drilling costs have escalated and we would expect this trend to continue, but our commodity prices have also increased at the same time.

Recent Accounting Pronouncements

SFAS 123, as originally issued in 1995, established as preferable a fair-value-based method of accounting for share-based payment transactions with employees. However, that Statement permitted entities the option of continuing to apply the guidance in APB Opinion No. 25, as long as the footnotes to financial statements disclosed what net income would have been had the preferable fair-value-based method been used. In 2003, the Company adopted the fair–value-based method of accounting for share based payment transactions with employees described in SFAS 123 using the prospective transition method.

In December 2004, the Financial Accounting Standard Board ("FASB"), issued SFAS No. 123(R), *"Share-Based Payment."* SFAS 123(R) will provide investors and other users of financial statements with more complete and neutral financial information by requiring that the compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the fair value of the equity or liability instruments issued.

SFAS 123(R) covers a wide range of share-based compensation arrangements, including share options, restricted share plans, performance-based awards, share appreciation rights, and employee share purchase plans. SFAS 123(R) replaces FASB SFAS 123, *"Accounting for Stock-Based Compensation,"* and supersedes APB Opinion No. 25, *"Accounting for Stock Issued to Employees."*

Public entities (other than those filing as small business issuers) were required to apply SFAS 123(R) as of the first interim or annual reporting period that begins after June 15, 2005. In April 2005, the Securities and Exchange Commission adopted a rule that amended the required application date of SFAS 123(R) from interim or annual reporting periods beginning after June 15, 2005, to the beginning of the entity's next fiscal year. We plan to use the modified prospective transition method under which we will record as compensation expense over the requisite service period the fair value of all new options and previously granted options for which the requisite service had not been rendered as of January 1, 2006. We estimate that the adoption of SFAS 123(R), will result in compensation expense, related to options outstanding as of December 31, 2005, of approximately $900,000, $600,000, $400,000, $200,000, $80,000 and $5,000 for 2006, 2007, 2008, 2009, 2010 and 2011, respectively, based on our estimates of the fair value of those options.

In May 2005, the FASB issued SFAS No. 154, *"Accounting Changes and Error Corrections,"* a replacement of APB Opinion No. 20 and FASB SFAS No. 3, which changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS No. 154 applies to all voluntary changes in accounting principles and also to changes required by an accounting pronouncement that does not contain specific transition provisions. SFAS No. 154 carries forward without change the guidance contained in APB Opinion No. 20, *"Accounting Changes,"* for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. We adopted SFAS No. 154 effective January 1, 2006 and the adoption may have a material impact on our financial position and results of operations if we have an accounting change.

Item 7a. Quantitive and Qualitative Disclosure About Market Risk

The following quantitative and qualitative information is provided about market risks and derivative instruments to which Parallel was a party at December 31, 2005, and from which Parallel may incur future earnings, gains or losses from changes in market interest rates and oil and natural gas prices.

Interest Rate Sensitivity as of December 31, 2005

Our only financial instruments sensitive to changes in interest rates are our bank debt and interest rate swaps. As the interest rate is variable and reflects current market conditions, the carrying value of our bank debt approximates the fair value. The table below shows principal cash flows and related weighted average interest rates by expected maturity dates. Weighted average interest rates were determined using weighted average interest paid and accrued in December, 2005. You should read Note 8 to the consolidated financial statements for further discussion of our debt that is sensitive to interest rates.

(dollars in thousands)	2006	2007	2008	2009	2010	Total
Variable rate debt	$ —	$ —	$ —	$ —	$ 100,000	$ 100,000
Revolving Credit Facility (secured)						
Average interest rate	6.40%	6.40%	6.40%	6.40%	6.40%	
Term Loan (Second Lien)						
Average interest rate	9.00%	9.00%	9.00%	9.00%	9.00%	

At December 31, 2005, we had bank loans in the amount of approximately $100.0 million outstanding at an average interest rate of 7.7%. Under our revolving credit facility, we may elect an interest rate based upon the agent bank's base lending rate or the LIBOR rate, plus a margin ranging from 2.00% to 2.50% per annum, depending on our borrowing base usage. The interest rate we are required to pay, including the applicable margin, may never be less than 5.00%. Under our second lien term loan facility, we may elect an interest rate based upon an alternate base rate, or the LIBOR rate, plus a margin of 4.50%.

As of December 31, 2005, we had employed a fixed interest rate swap contract with BNP Paribas, based on the 90-day LIBOR rates at the time of the contract. This interest rate swap is treated as a cash flow hedge as defined by SFAS 133. This interest rate swap is on $10 million of our variable rate debt for all of 2006. We will continue to pay the variable interest rates for this portion of our borrowing on the Revolving Credit Facility, but due to the interest rate swap, we have fixed the rate at 4.05%. Under the terms of this contract, in periods during which the fixed interest rate stated in the agreement exceeds the variable rate (which is based on the 90 day LIBOR rate), we pay to the counterparties an amount determined by applying this excess fixed rate to the notional amount of the contract. In periods when the variable rate exceeds the fixed rate stated in the swap contract, the counterparties pay an amount to us determined by applying the excess of the variable rate over the stated fixed rate. As of December 31, 2005, the fair market value of this interest rate swap was $69,000.

As of December 31, 2005, we had also employed additional fixed interest rate swap contracts with BNP and Citibank, NA based on the 90-day LIBOR rates at the time of the contracts. However, these contracts are accounted for by "mark to market" accounting as prescribed in SFAS 133. These contracts will not be offset against the future interest we will pay on our bank borrowings identified above. Nonetheless, we view these contracts as additional protection against future interest rate volatility. Below is a table describing the nature of these interest rate swaps and the fair market value of these contracts as of December 31, 2005.

Period of Time	Notional Amounts	Weighted Average Fixed Interest Rates	Estimated Fair Market Value at December 31, 2005
	(dollars in millions)		*(dollars in thousands)*
January 1, 2006 thru December 31, 2006(1)	$ 10	4.05%	$ 69
January 1, 2006 thru December 31, 2006	$ 90	4.41%	299
January 1, 2007 thru December 31, 2007	$ 100	4.62%	118
January 1, 2008 thru December 31, 2008	$ 100	4.86%	(111)
January 1, 2009 thru December 31, 2009	$ 50	5.06%	(110)
January 1, 2010 thru October 31, 2010	$ 50	5.15%	(94)
Total Fair Market Value			$ 171

(1) Designated as a cash flow hedge.

Commodity Price Sensitivity as of December 31, 2005

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Market risk refers to the risk of loss from adverse changes in oil and natural gas prices. Realized pricing is primarily driven by the prevailing domestic price for crude oil and spot prices applicable to the region in which we produce natural gas. Historically, prices received for oil and natural gas production have been volatile and unpredictable. We expect pricing volatility to continue. Oil prices ranged from a low of $36.43 per barrel to a high of $65.63 per barrel during 2005. Natural gas prices we received during 2005 ranged from a low of $2.22 per Mcf to a high of $15.43 per Mcf. A significant decline in the prices of oil or natural gas could have a material adverse effect on our financial condition and results of operations.

We employ various derivative instruments in order to minimize our exposure to the commodity price volatility discussed above. As of December 31, 2005, we had employed put options, costless collars, collars and swaps in order to protect against this price volatility. Although all of the contracts that we have entered into are viewed as protection against this price volatility, all but one of these contracts are accounted for by the "mark to market" accounting method as prescribed in SFAS 133.

As of December 31, 2005, we had one commodity swap contract with BNP that was designated as a cash flow hedge. This contract is for a total of 265,500 barrels of crude oil production in 2006 at a NYMEX Swap Price of $23.04 per Bbl. This contract expires December 20, 2006.

Below is a description of our active commodity contracts as of December 31, 2005.

Put Options. We purchased put options or "floors" on volumes of 3,000 MMBtu per day for a total of 642,000 MMBtu during the seven month period from April 1, 2006 through October 31, 2006 at an average floor price of $7.17 per MMBtu for a total consideration of approximately $230,000. The puts have fair market value of $174,000 as of December 31, 2005.

Collars. Collars are contracts which combine both a put option or "floor" and a call option or "ceiling". These contracts may not involve payment or receipt of cash at inception, depending upon "ceiling" and "floor" strike prices.

A summary of our collar positions at December 31, 2005 is as follows:

		NyMex Oil Prices			Houston Ship Channel Gas Prices		WAHA Gas Prices		
Period of Time	Barrels of Oil	Floor	Cap	MMBtu of Natural Gas	Floor	Cap	Floor	Cap	Fair Market Value
									(dollars in thousands)
January 1, 2006 thru December 31, 2006	289,800	$ 48.22	$ 75.83	—	$ —	$ —	$ —	$ —	$ (1,122)
April 1, 2006 thru October 31, 2006	—	$ —	$ —	428,000	$ 7.50	$ 13.90	$ —	$ —	52
April 1, 2006 thru October 31, 2006	—	$ —	$ —	214,000	$ —	$ —	$ 9.00	$ 14.55	181
January 1, 2007 thru December 31, 2007	219,000	$ 52.50	$ 83.00	—	$ —	$ —	$ —	$ —	230
April 1, 2007 thru October 31, 2007	—	$ —	$ —	214,000	$ 6.00	$ 11.05	$ —	$ —	(145)
January 1, 2008 thru December 31, 2008	109,800	$ 55.00	$ 76.50	—	$ —	$ —	$ —	$ —	153
January 1, 2009 thru December 31, 2009	91,250	$ 55.00	$ 73.00	—	$ —	$ —	$ —	$ —	126
January 1, 2010 thru December 31, 2010	76,000	$ 55.00	$ 71.00	—	$ —	$ —	$ —	$ —	113
Total Fair Market Value									$ (412)

Commodity Swaps. Generally, swaps are an agreement to buy or sell a specified commodity for delivery in the future, but at an agreed fixed price. Swap transactions convert a floating or market price into a fixed price. For any particular swap transaction, the counterparty is required to make a payment to us if the reference price for any settlement period is less than the swap or fixed price for such derivative contract, and we are required to make a payment to the counterparty if the reference price for any settlement period is greater than the swap or fixed price for such derivative contract.

We have entered into oil and gas swap contracts with BNP Paribas. A recap for the period of time, number of Bbls, and weighted average swap prices are as follows:

Period of Time	Barrels of Oil	Nymex Oil Swap Price	Fair Market Value
			(dollars in thousands)
January 1, 2006 thru December 20, 2006[(1)]	265,500	$ 23.04	$ (10,457)
January 1, 2006 thru December 31, 2006	182,500	$ 36.35	(4,806)
January 1, 2007 thru December 31, 2007	474,500	$ 34.36	(13,327)
January 1, 2008 thru December 31, 2008	439,200	$ 33.37	(11,741)
Total fair market value			$ (40,331)

(1) Designated as a cash flow hedge.

We have recognized a cumulative total of $625,000 in ineffectiveness on our one remaining commodity swap that we have designated as a cash flow hedge.

Item 8. Financial Statements and Supplementary Data

Parallel's consolidated financial statements and supplementary financial data are included in this report beginning on page 80 [F-1].

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Resignation of KPMG LLP

On December 4, 2003, we received written notice from KPMG LLP confirming that the client-auditor relationship between Parallel and KPMG had ceased as of December 2, 2003. KPMG resigned due to an independence issue arising from retirement benefits paid to Ray M. Poage, a former partner of KPMG who is also a director of Parallel. For the period from April 28, 2003 to December 2, 2003, Mr. Poage received eight monthly retirement payments from KPMG, each in the amount of $856.26.

KPMG's audit reports on our consolidated financial statements for the two fiscal years ended December 31, 2001 and December 31, 2002 did not contain an adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principles.

During the two fiscal years ended December 31, 2001 and December 31, 2002 and the period from January 1, 2003 through December 2, 2003, there were no disagreements between Parallel and KPMG on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which, if not resolved to the satisfaction of KPMG would have caused it to make reference to the subject matter of the disagreement in connection with its report on the consolidated financial statements for that period, nor have there been any reportable events as defined under Item 304(a)(1)(v) of regulation S-K during such period.

We provided KPMG with a copy of our Current Report on Form 8-K, dated December 2, 2003 and filed with the SEC on December 9, 2003, reporting KPMG's resignation. We requested that KPMG furnish us with a letter addressed to the Securities and Exchange Commission stating whether it agreed with the statements we made in our Form 8-K Report and, if not, stating the respects in which it did not agree. KPMG's letter, filed as an exhibit to the form 8-K Report, expressed agreement with our statements.

Engagement of BDO Seidman, LLP

Effective January 20, 2004, we engaged BDO Seidman, LLP as the principal accountant to audit our consolidated financial statements. The decision to engage BDO Seidman was recommended and approved by the Audit Committee of our Board of Directors.

During the two fiscal years ended December 31, 2001 and December 31, 2002 and during any subsequent interim period, BDO Seidman was not engaged as either the principal accountant to audit our consolidated financial statements or as an independent accountant to audit a significant subsidiary and on whom the principal accountant was expected to express reliance on its report. In addition, during the two most recent fiscal years and during any subsequent interim period prior to engaging BDO Seidman, neither we, nor anyone on our behalf consulted BDO Seidman regarding (a) either the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on our consolidated financial statements, and no written report was provided to us and no oral advice was provided to us by BDO Seidman which was considered by us in reaching a decision as to the accounting, auditing or financial reporting issues; and (b) there was no matter that was a subject of disagreement as defined in paragraph 304(a)(1)(v) of Regulation S-K.

Item 9a. Controls and Procedures

Disclosure Controls and Procedures

We use disclosure controls and procedures to help ensure that information we are required to disclose in reports that we file with the Securities and Exchange Commission is accumulated and communicated to our management and recorded, processed, summarized and reported with in the time periods specified by the SEC. As of the end of the period covered by this Annual Report on Form 10-K, the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) promulgated under the Securities Exchange Act of 1934) was evaluated by Larry C. Oldham, our President and Chief Executive Officer (principal executive officer), and Steven D. Foster, our Chief Financial Officer (principal financial officer). As described below under Management's Annual Report on Internal Control over Financial Reporting, we identified a material weakness in the Company's internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)). As a result of this material weakness, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this Annual Report on Form 10-K, our disclosure controls and procedures were not effective.

In light of this material weakness, in preparing its financial statements as of and for the fiscal year ended December 31, 2005, Parallel performed additional analyses and procedures pertaining to our accounting for derivative instruments to ensure that our consolidated financial statements included in this Annual Report on Form 10-K have been prepared in accordance with generally accepted accounting principles and to restate previously issued financial statements for the year ended December 31, 2004, the quarters ended March 31, June 30 and September 30, 2005, and the quarters ended September 30 and December 31, 2004. Detailed disclosures concerning this restatement are included in our consolidated financial statements included elsewhere herein.

Management's Report on Internal Control Over Financial Reporting

Management of Parallel is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934.

Our internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and financial officers; and, effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Our internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of management and board of directors of Parallel; and, (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of Parallel's internal control over financial reporting as of December 31, 2005. In making this assessment, management used the criteria set forth in *Internal Control – Integrated Framework*, issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. In March 2006, management concluded that its designation of certain derivatives contracts as hedges was not adequately documented at the inception of the related contracts. Therefore, the derivative contracts did not qualify for hedge accounting treatment under GAAP. Accordingly, we restated our consolidated financial statements for the year ended December 31, 2004, the quarters ended March 31, June 30, and September 30, 2005 and the quarters ended September 30 and December 31, 2004 to account for the derivative contracts as non-hedging derivatives.

Management evaluated the impact of this restatement on Parallel's assessment of its internal controls over financial reporting. Management has concluded that the controls in place relating to the documentation of hedge designations were not properly designed to provide reasonable assurance that these derivative contracts would be properly recorded and disclosed in the financial statements in accordance with GAAP; and, that this represents a material weakness in our internal control over financial reporting as of December 31, 2005. As a result of the assessment performed and the material weakness noted, management has concluded that Parallel's internal control over financial reporting was not effective as of December 31, 2005. Further, we have determined that these control deficiencies existed with respect to certain aspects of our historical financial reporting and, accordingly, we have concluded that our prior disclosures regarding the sufficiency of our disclosure controls may not have been correct.

BDO Seidman, LLP, the independent registered public accounting firm who also audited our consolidated financial statements, has issued an attestation report on management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, which is filed herewith.

Changes in Internal Controls

During the fourth quarter of fiscal 2005, there were no changes in our internal controls over financial reporting that materially affected or are reasonably likely to materially affect these internal controls over financial reporting.

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

To the Board of Directors and Shareholders of
Parallel Petroleum Corporation
Midland, Texas

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting, that Parallel Petroleum Corporation did not maintain effective internal control over financial reporting as of December 31, 2005, because of the effect of material weaknesses identified in management's assessment, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Parallel Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weakness has been identified and included in management's assessment:

> Controls in place relating to the documentation of hedge designations were not properly designed to provide reasonable assurance that the derivative contracts would be properly recorded and disclosed in the financial statements in accordance with accounting principles generally accepted in the United States of America.

This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2005, and this report does not affect our report dated March 10, 2006 on those consolidated financial statements.

In our opinion, management's assessment that Parallel Petroleum Corporation did not maintain effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, because of the effect of the material weakness described above on the achievement of the objectives of the control criteria, Parallel Petroleum Corporation has not maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Parallel Petroleum Corporation as of December 31, 2005 and 2004, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005, and our report dated March 10, 2006 expressed an unqualified opinion.

/s/ BDO Seidman, LLP
Houston, Texas
March 10, 2006

Item 9b. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

The Directors and executive officers of Parallel at March 1, 2006 are as follows:

Name	Age	Director Since	Position with Company
Thomas R. Cambridge(1)	70	1985	Chairman of the Board of Directors
Larry C. Oldham(1)	52	1979	Director, President and Chief Executive Officer
Dewayne E. Chitwood(2)(3)(4)	69	2000	Director
Martin B. Oring(1)(2)(3)(4)	60	2001	Director
Ray M. Poage(1)(2)(3)(4)	58	2003	Director
Jeffrey G. Shrader(1)(2)(4)	55	2001	Director
Donald E. Tiffin	48	—	Chief Operating Officer
Eric A. Bayley	57	—	Vice President of Corporate Engineering
John S. Rutherford	46	—	Vice President of Land and Administration
Steven D. Foster	50	—	Chief Financial Officer

(1) Member of Hedging and Acquisition Committee
(2) Member of Compensation Committee
(3) Member of Audit Committee
(4) Member of Corporate Governance and Nominating Committee

Thomas R. Cambridge, is the Chairman of the Board of Directors of Parallel. He is an independent petroleum geologist engaged in the exploration for, development and production of oil and natural gas. From 1970 until 1990, such activities were carried out primarily through Cambridge & Nail Partnership, a Texas general partnership. Since 1990, such activities have been carried out through Cambridge Production, Inc., a Texas corporation, and Cambridge Partnership, Ltd., a Texas limited partnership. Mr. Cambridge has served as a Director of Parallel since February 1985 and as Chairman of the Board since October, 1985; as President during the period from October, 1985 to October, 1994 and as Chief Executive Officer from October, 1985 to January, 2004. He received a Bachelors degree in geology from the University of Nebraska in 1958 and a Masters of Science degree in 1960.

Mr. Oldham is a founder of Parallel and has served as an officer and Director since its formation in 1979. Mr. Oldham became President of Parallel in October, 1994, and served as Executive Vice President before becoming President. Effective January 1, 2004, Mr. Oldham replaced Mr. Cambridge as Chief Executive Officer. Mr. Oldham received a Bachelor of Business Administration degree from West Texas State University in 1975.

Mr. Chitwood is president, chief executive officer and a manager of Wes-Tex Holdings, LLC, the general partner of Wes-Tex Drilling Company, L.P., a partnership engaged in oil and natural gas exploration and production. During the five-year period preceding Mr. Chitwood's association with Wes-Tex in 1997, he was an owner and founder of CBS Insurance L.P., a general insurance agency.

Mr. Oring is the owner of Wealth Preservation, LLC, a financial counseling firm founded by Mr. Oring in January, 2001. From 1998 to December, 2000, Mr. Oring was Managing Director Executive Services of Prudential Securities Incorporated, and from 1996 to 1998, Mr. Oring was Managing Director Capital Markets of Prudential Securities Incorporated. From 1989 to 1996, Mr. Oring was Manager of Capital Planning for The Chase Manhattan Corporation. At March 1, 2006, Mr. Oring was Chairman of the Hedging and Acquisitions Committee of the Board of Directors of Parallel.

Mr. Poage was a partner in KPMG LLP from 1980 to June 2002 when he retired. Mr. Poage's responsibilities included supervising and managing both audit and tax professionals and providing services, primarily in the area of taxation, to private and publicly held companies engaged in the oil and natural gas industry. At March 1, 2006 Mr. Poage was Chairman of the Audit Committee of the Board of Directors of Parallel.

Mr. Shrader has been a shareholder in the law firm of Sprouse Shrader Smith, Amarillo, Texas, since January, 1993. He has also served as a director of Hastings Entertainment, Inc. since 1992. At March 1, 2006 Mr. Shrader was Chairman of the Compensation Committee of the Board of Directors of Parallel.

Mr. Tiffin served as Vice President of Business Development from June, 2002 until January 1, 2004 when he became Chief Operating Officer. From August, 1999 until May, 2002, Mr. Tiffin served as General Manager of First Permian, L.P. and from July, 1993 to July, 1999, Mr. Tiffin was the Drilling and Production Manager in the Midland, Texas office of Fina Oil and Chemical Company. Mr. Tiffin graduated from the University of Oklahoma in 1979 with a Bachelor of Science degree in Petroleum Engineering.

Mr. Bayley has been Vice President of Corporate Engineering since July, 2001. From October, 1993 until July, 2001, Mr. Bayley was employed by Parallel as Manager of Engineering. From December, 1990 to October, 1993, Mr. Bayley was an independent consulting engineer and devoted substantially all of his time to Parallel. Mr. Bayley graduated from Texas A&M University in 1978 with a Bachelor of Science degree in Petroleum Engineering. He graduated from the University of Texas of the Permian Basin in 1984 with a Master's of Business Administration degree.

Mr. Rutherford has been Vice President of Land and Administration of Parallel since July, 2001. From October 1993 until July, 2001, Mr. Rutherford was employed as Manager of Land/Administration. From May, 1991 to October, 1993, Mr. Rutherford served as a consultant to Parallel, devoting substantially all of his time to Parallel's business. Mr. Rutherford graduated from Oral Roberts University in 1982 with a degree in Education, and in 1986 he graduated from Baylor University with a Master's degree in Business Administration.

Mr. Foster has been the Chief Financial Officer of Parallel since June, 2002. From November, 2000 to May, 2002, Mr. Foster was the Controller and Assistant Secretary of First Permian, L.P. and from September, 1997 to November 2000, he was employed by Pioneer Natural Resources, USA in the capacities of Director of Revenue Accounting and Manager of Joint Interest Accounting. Mr. Foster graduated from Texas Tech University in 1977 with a Bachelor of Business Administration degree in accounting. He is a certified public accountant.

Directors hold office until the annual meeting of stockholders following their election or appointment and until their respective successors have been dully elected or appointed.

Officers are appointed annually by the Board of Directors to serve at the Board's discretion and until their respective successors in office are duly appointed.

There are no family relationships between any of Parallel's directors or officers.

Consulting Arrangements

As part of our overall business strategy, we continually monitor our general and administrative expenses. Decisions regarding our general and administrative expenses are made within parameters we believe to be compatible with our size, the level of our activities and projected future activities. Our goal is to keep general and administrative expenses at acceptable levels, without impairing the quality of services and organizational structure necessary for conducting our business. In this regard, we retain outside advisors and consultants from time to time to provide technical and administrative support services in the operation of our business.

Corporate Governance

Under the Delaware General Corporation Law and Parallel's bylaws, our business, property and affairs are managed by or under the direction of the Board of Directors. Members of the Board are kept informed of Parallel's business through discussions with the Chairman of the Board, the Chief Executive Officer and other officers, by reviewing materials provided to them and by participating in meetings of the Board and its committees. We currently have six members of the Board. The Board has determined that all of the Directors, other than Mr. Cambridge and Mr. Oldham, are "independent" for the purposes of NASD Rule 4200(a) (15). The Board based these determinations primarily on responses of the Directors and executive officers to questions regarding employment and compensation history, affiliations and family and other relationships and on discussions among the Directors.

The Board has four standing committees:

- the Audit Committee;
- the Corporate Governance and Nominating Committee;
- the Compensation Committee; and
- the Hedging and Acquisitions Committee.

Audit Committee

The audit Committee reviews the results of the annual audit of our consolidated financial statements and recommendations of the independent auditors with respect to our accounting practices, policies and procedures. As prescribed by our Audit Committee charter, the Audit Committee also assists the Board of Directors in fulfilling its oversight responsibilities, reviewing our systems of internal accounting and financial controls, and the independent audit of our consolidated financial statements.

The Audit Committee of the Board of Directors consists of three directors, all of whom have no financial or personal ties to Parallel (other than director compensation and equity ownership as described in this Annual Report on Form 10-K) and meet the Nasdaq standards for independence. The Board of Directors has determined that at least one member of the Audit Committee, Ray M. Poage, meets the criteria of an "audit committee financial expert" as that term is defined in Item 401 (h) of Regulation S-K, and is independent for purposes of Nasdaq listing standards and Section 10A (m) (3) of the Securities Exchange Act of 1934, as amended. Mr. Poage's background and experience includes service as a partner of KPMG LLP where Mr. Poage participated extensively in accounting, auditing and tax matters related to the oil and natural gas business. The Audit Committee operates under a charter, which was revised in March 2004. The charter can be viewed in our website on www.plll.com.

Since October 2003, the members of the Audit Committee have been and continue to be Messrs. Poage (Chairman), Chitwood and Oring.

Corporate Governance and Nominating Committee

At its March 15, 2004 meeting, the Board formed a Corporate Governance and Nominating Committee and adopted a charter for this new committee. The functions of the Corporate Governance and Nominating Committee will include: recommending to the Board of Directors nominees for election as directors of Parallel, and making recommendations to the Board of Directors from time to time as to matters of corporate governance. Upon formation of the Corporate Governance and Nominating Committee, the Board of Directors appointed Dewayne E. Chitwood, Martin B. Oring, Charles R. Pannill, Ray M. Poage and Jeffrey G. Shrader to serve as members. These Directors continue to serve on the Corporate Governance and Nominating Committee, except that Mr. Pannill ceased to be a member of the committee upon his retirement from the Board of Directors in June 2004. The Corporate Governance and Nominating Committee will operate under the charter setting out the functions and responsibilities of this committee. A copy of the charter can be viewed in our website at www.plll.com.

The committee will consider candidates for Director suggested by stockholders. Stockholders wishing to suggest a candidate for Director should write to any one of the members of the committee at his address shown under Item 12 of this Annual Report on Form 10-K. Suggestions should include:

- a statement that the writer is a stockholder and is proposing a candidate for consideration by the committee;
- the name of and contact information for the candidate;
- a statement of the candidate's age, business and educational experience;
- information sufficient to enable the committee to evaluate the candidate;

- a statement detailing any relationship between the candidate and any joint interest owners, customer, supplier or competitor of Parallel;
- detailed information about any relationship or understanding between the proposing stockholder and the candidate; and
- a statement that the candidate is willing to be considered and willing to serve as a Director if nominated and elected.

Compensation Committee

The members of the Compensation Committee during 2004 were Dewayne E. Chitwood, Martin B. Oring, Ray M. Poage and Jeffrey G. Shrader and Charles R. Pannill, until his retirement from the Board of Directors in June 2004. Messrs. Chitwood, Oring, Poage, and Shrader continue to serve as members of the Compensation Committee. Mr. Shrader presently acts as the Chairman of the Compensation Committee. The Compensation Committee's responsibilities include reviewing and recommending to the Board the compensation and terms of benefit arrangements with Parallel's officers, and making of awards under such arrangements.

Hedging and Acquisitions Committee

The Hedging and Acquisitions Committee presently consists of five Directors, including Messrs. Oring, Poage, Shrader, Oldham and Cambridge. Mr. Oring presently serves as chairman of this committee. With respect to derivative contracts, the committee reviews, assists, and advises management on overall risk management strategies and techniques. The committee strives to implement prudent commodity and interest rate derivative arrangements, and monitors our compliance with certain covenants in our revolving credit facility. The Hedging and Acquisitions Committee also reviews with management plans and strategies for pursuing acquisitions.

Code of Ethics

On March 15, 2004, the Board adopted a code of ethics as part of our efforts to comply with the Sarbanes-Oxley Act of 2002 and rule changes made by the Securities and Exchange Commission and Nasdaq. Our code of ethics applies to all of our directors, officers and employees, including our chief executive officer, chief financial officer and all other financial officers and executives. You may review the code of ethics on our website at www.plll.com. A copy of our code of ethics has also been filed with the Securities and Exchange Commission and is incorporated by reference as an exhibit to this Annual Report on Form 10-K. We will provide without charge to each person, upon written or oral request, a copy of our code of ethics.

Requests should be directed to:

Manager of Investor Relations
Parallel Petroleum Corporation
1004 N. Big Spring, Suite 400
Midland, Texas 79701
Telephone: (432) 684-3727

Stockholder Communications with Directors

Parallel stockholders who want to communicate with any individual Director can write to that Director at his address shown under Item 12 of this Annual Report on Form 10-K.

Your letter should indicate that you are a Parallel stockholder. Depending on the subject matter, the Director will:

- if you request, forward the communication to the other Directors;
- request that management handle the inquiry directly, for example where it is a request for information about the company or it is a stock-related matter; or
- not forward the communication to the other Directors or management if it is primarily commercial in nature or if it relates to an improper or irrelevant topic.

Director Attendance at Annual Meetings

We typically schedule a Board meeting in conjunction with our annual meeting of stockholders and expect that our Directors will attend, absent a valid reason, such as illness or a schedule conflict. Last year, all six of the individuals then serving as Directors attended our annual meeting of stockholders.

Item 11. Executive Compensation

Summary of Annual Compensation

The table below shows a summary of the types and amounts of compensation paid for the last three fiscal years to Mr. Cambridge, our Chairman of the Board, and to Mr. Oldham, our President and Chief Executive Officer. The table also includes a summary of the types and amounts of compensation paid to our other four executive officers for the years indicated.

Compensation Table

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation ($)[2]	Restricted Stock Awards ($)	Securities Underlying Options/ SAR (#)	LTIP Payouts ($)	All Other Compensation ($)
T.R. Cambridge	2005	$ 120,000	$ 60,000	$ —	0	0	0	0
Chairman of the Board	2004[1]	$ 110,000	$ 10,000	$ —	0	0	0	0
	2003	$ 110,000	$ 25,000	$ —	0	0	0	0
L.C. Oldham	2005	$ 275,000	$ 201,525	$ 35,381[3]				$ 16,500[4]
President, Chief Executive	2004	$ 250,000	$ 11,019	$ 27,183	0	0	0	$ 15,000
Officer and Director	2003	$ 191,000	$ 61,391	$ 22,802	0	0	0	$ 11,460
D.E. Tiffin	2005	$ 241,667	$ 138,917	$ 24,522[5]				$ 14,500[6]
Chief Operating Officer	2004	$ 220,000	$ 10,015	$ 23,560	0	0	0	$ 13,560
	2003	$ 171,140	$ 44,391	$ 17,464	0	0	0	$ 10,268
E.A. Bayley	2005	$ 153,667	$ 51,417	$ 21,248[7]				$ 9,220[8]
Vice President	2004	$ 140,000	$ 7,101	$ 24,500	0	0	0	$ 8,400
	2003	$ 110,000	$ 23,391	$ 16,470	0	0	0	$ 6,600
J.S. Rutherford	2005	$ 153,667	$ 51,417	$ 22,525[9]				$ 9,220[10]
Vice President	2004	$ 140,000	$ 7,062	$ 23,357	0	0	0	$ 8,400
	2003	$ 110,000	$ 23,391	$ 15,763	0	0	0	$ 6,600
S.D. Foster	2005	$ 154,542	$ 76,417	$ 28,182[11]				$ 9,273[12]
Chief Financial Officer	2004	$ 140,000	$ 7,033	$ 27,983	0	0	0	$ 8,760

(1) Mr. Cambridge's position as Chief Executive Officer ceased on January 1, 2004 when Mr. Oldham became Chief Executive Officer.

(footnotes continued on following page)

(2) Under rules of the Securities and Exchange Commission, the dollar value of perquisites and personal benefits may be excluded from this column if the aggregate amount of such compensation is the lesser of either $50,000 or 10% of the total annual salary and bonus reported for the named executive officers. However, for 2005 and 2004 we have identified the following amounts:

		Mr. Cambridge	Mr. Oldham	Mr. Tiffin	Mr. Bayley	Mr. Rutherford	Mr. Foster
Personal use of club memberships[(a)]							
	2005	$ —	$ —	$ —	$ —	$ 2,150	$ 2,501
	2004	$ —	$ —	$ —	$ 113	$ 3,672	$ 4,407
Personal use of company car[(b)]							
	2005	$ —	$ 3,338	$ —	$ 4,075	$ 2,544	$ —
	2004	$ —	$ 2,507	$ —	$ 6,189	$ 3,107	$ —
Car allowance							
	2005	$ —	$ —	$ 6,000	$ —	$ —	$ 6,000
	2004	$ —	$ —	$ 6,000	$ —	$ —	$ 6,000
Personal income tax preparation and financial planning services							
	2005	$ —	$ —	$ —	$ —	$ —	$ —
	2004	$ —	$ 3,588	$ —	$ —	$ —	$ —
Personal use of office space[(c)]							
	2005	$ —	$ 1,500	$ —	$ —	$ —	$ —
Personal use of charter aircraft[(d)]							
	2005	$ —	$ 7,500	$ —	$ —	$ —	$ —

(a) The value of personal use of club memberships was determined by multiplying monthly dues by a fraction equal to actual personal expenses divided by total expenses. All employees reimbursed us for their personal expenses.

(b) Personal use of a company car is based on the lease value method published by the Internal Revenue Service for fringe benefits.

(c) Includes personal use of office space by Mr. Oldham's wife for charitable, civic and personal activities. The value is determined by multiplying the number of square feet in the office by the cost per square foot paid by Parallel under its lease agreement covering its executive offices.

(d) Includes air travel costs associated with Mr. Oldham's wife accompanying him on business trips. The amount shown is equal to what the cost would have been for non-refundable roundtrip commercial airfare.

(3) These amounts include insurance premiums for nondiscriminatory group life, medical, disability, long-term care and dental insurance as follows: $22,990 for 2005; $21,088 for 2004; and $19,697 for 2003.

(4) This amount represents Parallel's contribution to Mr. Oldham's individual retirement account maintained under the 408(K) simplified employee pension plan/individual retirement account for 2003 and 2004 and 401(K) retirement account for 2005.

(5) This amount includes insurance premiums for nondiscriminatory group life, medical, disability and dental insurance as follows: $18,522 for 2005; $17,560 for 2004; and $16,964 for 2003.

(6) This amount represents Parallel's contribution to Mr. Tiffin's individual retirement account maintained under the 408(K) simplified employee premium plan/individual retirement account for 2003 and 2004 and 401(K) retirement account for 2005.

(7) This amount includes insurance premiums for nondiscriminatory group life, medical, disability, long-term care and dental insurance as follows: $17,173 for 2005; $18,198 for 2004; and $16,470 for 2003.

(8) This amount represents Parallel's contribution to Mr. Bayley's individual retirement account maintained under the 408(K) simplified employee pension plan/individual retirement account for 2003 and 2004 and 401(K) retirement account for 2005.

(9) This amount includes insurance premiums for nondiscriminatory group life, medical, disability and dental insurance as follows: $17,831 for 2005; $16,578 for 2004; and $15,763 for 2003.

(10) This amount represents Parallel's contribution to Mr. Rutherford's individual retirement account maintained under the 408(K) simplified employee premium plan/individual retirement account for 2003 and 2004 and 401(K) retirement account for 2005.

(11) This amount includes insurance premiums for nondiscriminatory group life, medical, disability, long-term care and dental insurance as follows: $19,681 for 2005 and $17,576 for 2004.

(12) This amount represents Parallel's contribution to Mr. Foster's individual retirement account maintained under the 408(K) simplified employee premium plan/individual retirement account for 2004 and 401(K) retirement account for 2005.

Stock Options

We use stock options as part of the overall compensation of directors, officers and employees. However, we did not grant any stock options in 2004 to any of the executive officers named in the Summary Compensation Table. Summary descriptions of our stock option plans are included in this report so you can review the types of options we have granted in the past and the significant features of our stock options.

In the table below, we show certain information about the exercise of stock options in 2005 and the value of unexercised stock options held by the named executive officers at December 31, 2005.

Aggregated Option/SAR Exercises in Last Fiscal Year and Fiscal Year-End Option/SAR Values

Name	Shares Acquired on Exercise	Value Realized ($)[1]	Number of Securities Underlying Unexercised Options at Fiscal Year-End (#)		Value of Unexercised In-the-Money Options at Fiscal Year-End ($)[2]	
			Exercisable	Unexercisable	Exercisable	Unexercisable
T.R. Cambridge	0	0	300,000	0	3,926,000	0
L.C. Oldham	309,000	4,409,320	46,000	45,000	616,860	541,800
E.A. Bayley	40,000	449,480	125,000	0	1,539,500	0
J.S. Rutherford	65,000	581,630	93,750	0	1,131,688	0
D.E. Tiffin	50,000	766,500	0	0	0	0
S.D. Foster	35,000	440,150	0	0	0	0

(1) The value realized is equal to the fair market value of a share of common stock on the date of exercise, less the exercise price of the stock options exercised.

(2) The value of unexercised in-the-money options is equal to the fair market value of a share of common stock at fiscal year-end ($17.01 per share), based on the last sale price of Parallel's common stock, less the exercise price.

Change of Control Arrangements

Stock Option Plans

Parallel's outstanding stock options and stock option plans contain certain change of control provisions which are applicable to Parallel's outstanding stock options, including the options held by our officers and Directors. For purposes of our options, a change of control occurs if:

- Parallel is not the surviving entity in a merger or consolidation;
- Parallel sells, leases or exchanges all or substantially all of its assets;
- Parallel is to be dissolved and liquidated;
- any person or group acquires beneficial ownership of more than 50% of Parallel's common stock; or
- in connection with a contested election of directors, the persons who were directors of Parallel before the election cease to constitute a majority of the Board of Directors.

If a change of control occurs, the Compensation Committee of the Board of Directors can:

- accelerate the time at which options may be exercised;
- require optionees to surrender some or all of their options and pay to each optionee the change of control value;
- make adjustments to the options to reflect the change of control; or
- permit the holder of the option to purchase, instead of the shares of common stock as to which the option is then exercisable, the number and class of shares of stock or other securities or property which the optionee would acquire under the terms of the merger, consolidation or sale of assets and dissolution if, immediately before the merger, consolidation or sale of assets or dissolution, the optionee had been the holder of record of the shares of common stock as to which the option is then exercisable.

The change of control value is an amount equal to, whichever is applicable:

- the per share price offered to Parallel's stockholders in a merger, consolidation, sale of assets or dissolution transaction;
- the price per share offered to Parallel's stockholders in a tender offer or exchange offer where a change of control takes place; or
- if a change of control occurs, other than from a tender or exchange offer, the fair market value per share of the shares into which the options being surrendered are exercisable, as determined by the Committee.

Incentive and Retention Plan

On September 22, 2004, the Compensation Committee of the Board of Directors approved and adopted an incentive and retention plan for Parallel's officers and employees. On September 24, 2004, the Board of Directors adopted the plan upon recommendation by the Compensation Committee.

The purpose of the plan is to advance the interests of Parallel and its stockholders by providing officers and employees with incentive bonus compensation which is linked to a corporate transaction. As defined in the plan, a corporate transaction means:

- an acquisition of Parallel by way of purchase, merger, consolidation, reorganization or other business combination, whether by way of tender offer or negotiated transaction, as a result of which Parallel's outstanding securities are exchanged or converted into cash, property and/or securities not issued by Parallel;
- a sale, lease, exchange or other disposition by Parallel of all or substantially all of its assets;
- the stockholders of Parallel approving a plan or proposal for the liquidation or dissolution of Parallel; or
- any combination of any of the foregoing.

The plan also recognizes the possibility of a proposed or threatened transaction and the need to be able to rely upon officers and employees continuing their employment, and that Parallel be able to receive and rely upon their advice as to the best interests of Parallel and its stockholders without concern that they might be distracted by the personal uncertainties and risks created by any such transaction. In this regard, the plan also provides for a retention payment upon the occurrence of a change of control, as defined below.

All members of Parallel's "executive group" are participants in the plan. For purposes of the plan, the "executive group" includes all executive officers of Parallel and any other officer employee of Parallel selected by the Compensation Committee in its sole discretion. In addition, the Committee may designate other non-officer employees of Parallel as participants in the plan who will also be eligible to receive a performance bonus upon the occurrence of a corporate transaction or a retention payment upon the occurrence of a change of control.

Generally, the plan provides for:

- the payment of a one-time performance bonus to eligible officers and employees upon the occurrence of a corporate transaction; or
- a one time retention payment upon a change of control of Parallel. A change of control is generally defined as the acquisition of beneficial ownership of 60% or more of the voting power of Parallel's outstanding voting securities by any person or group of persons, or a change in the composition of the Board of Directors of Parallel such that the individuals who, at the effective date of the plan, constitute the Board of Directors.

On August 23, 2005, the Compensation Committee of the Board of Directors of Parallel approved and adopted amendments to the incentive and retention plan, and on that same date, the Board of Directors approved the amendments upon recommendation by the Compensation Committee. Generally, the plan was amended to provide for 400,000 "additional base shares" with an associated "additional base price" of $8.62 per share.

The amount of these payments depends on future prices of Parallel's common stock, which is undeterminable until a triggering event occurs. In the case of a corporate transaction, the total cash obligation for performance bonuses is equal to the sum of (a) per share price received by all stockholders minus a base price of $3.73 per share, multiplied by 1,080,362 shares, plus (b) the per share price received by all stockholders minus an "additional base price" of $8.62 per share, multiplied by 400,000 "additional base shares". As an example, if the stockholders of Parallel received the December 31, 2005 per share price of $17.01 in a merger, tender offer or other corporate transaction, the total amount of cash performance bonuses payable to all plan participants would be [($17.01 – $3.73) x 1,080,362], plus [$17.01 – $8.62) x 400,000], or $17,703,207. If a change of control occurs, the total amount of cash retention payments to all plan participants would be equal to the sum of (a) per share closing price of Parallel's common stock on the day immediately preceding the change of control minus the base price of $3.73 per share, multiplied by 1,080,362, plus (b) the per share closing price of Parallel's common stock on the day immediately preceding the change of control minus an "additional base price" of $8.62 per share, multiplied by 400,000.

If a corporate transaction or change of control occurs, the Compensation Committee will allocate for payment to each member of the executive group such portion of the total performance bonus or retention payment as the Compensation Committee determines in its sole discretion. After making these allocations, if any part of the total performance bonus or retention payment amount remains unallocated, the Compensation Committee may allocate any remaining portion of the performance bonus or retention payment among all other participants in the plan. After all allocations of the performance bonus have been made, each participant's proportionate share of the performance bonus or retention payment will be paid in a cash lump sum.

Parallel's ultimate liability under the plan is not readily determinable because of the inability to predict the occurrence of a corporate transaction or change of control, or Parallel's stock price on the future date of any such corporate transaction or change of control. No liability will be recorded until such time as a corporate transaction or change of control becomes probable and the amount of the liability becomes determinable. The occurrence of a change of control or a corporate transaction could have a negative impact on Parallel's financial condition and results of option, depending upon the price of Parallel's common stock at the time of a change of control or corporate transaction.

The plan is entirely unfunded and the plan makes no provision for segregating any of Parallel's assets for payment of any amounts under the plan.

A participant's rights under the plan are not transferable.

The plan is administrated by the Compensation Committee of the Board of Directors of Parallel. The Compensation Committee has the power, in its sole discretion, to take such actions as may be necessary to carry out the provisions and purposes of the plan. The Compensation Committee has the authority to control and manage the operation and administration of the plan and has the power to:

- designate the officers and employees of Parallel and its subsidiaries who participate in the plan, in addition to the "Executive Group";
- maintain records and data necessary for proper administration of the plan;
- adopt rules of procedure and regulations necessary for the proper and efficient administration of the plan;
- enforce the terms of the plan and the rules and regulations it adopts;
- employ agents, attorneys, accountants or other persons; and
- perform any other acts necessary or appropriate for the proper management and administration of the plan.

The plan automatically terminates and expires on the date participants receive a performance bonus or retention payment.

Non-Officer Severance Plan

In January 2006, a Non-Officer Employee Severance Plan was implemented for the purpose of providing our non-officer employees with an incentive to remain employed by us. This plan provides for a one-time severance payment to non-officer employees equal to one year of their then current base salary upon the occurrence of a change of control within the meaning of the Plan. Based on the aggregate non-officer base salaries in effect as of December 31, 2005, if a change of control had occurred at December 31, 2005, the total severance amount payable under the plan would have been approximately $2.5 million.

Compensation of Directors

Stock

Effective July 1, 2004, we began paying an annual retainer fee to each non-employee Director in the form of shares of our common stock. Under the 2004 Non-Employee Director Stock Grant Plan, which is described below in more detail, each non-employee Director is entitled to receive an annual retainer fee in the form of shares of common stock having a value of $25,000. The shares of stock are automatically granted on the first day of July in each year. The actual number of shares received is determined by dividing $25,000 by the average daily closing price of the common stock on the Nasdaq Stock Market for the ten consecutive trading days commencing fifteen trading days before the first day of July of each year. On July 1, 2005, and in accordance with the terms of the plan, we issued a total of 11,596 shares of common stock to four non-employee Directors as follows: Jeffrey G. Shrader – 2,899 shares; Dewayne E. Chitwood – 2,899 shares; Martin B. Oring – 2,899 shares; and Ray M. Poage – 2,899 shares. We have 83,510 remaining shares of common stock to issue to directors under this arrangement.

Cash

Following stockholder approval of the 2004 Non-Employee Director Stock Grant Plan in June 2004, we reduced by one-half the per meeting and annual cash fees we had been paying to our non-employee Directors. We now pay each non-employee Director a cash fee of $750 for attendance at each meeting of the Board of Directors and each non-employee Director who is a member of a Board committee also receives:

- $375 per meeting for service on the Compensation Committee, with the Chairman of the Compensation Committee being entitled to receive an additional fee of $2,500 per year;
- $375 per meeting for service on the Audit committee, with the Chairman of the Audit Committee being entitled to receive an additional fee of $5,000 per year and each other Audit Committee member receiving $2,500 per year;
- $375 per meeting for service on the Corporate Governance and Nominating Committee, with the Chairman of the Corporate Governance and Nominating Committee being entitled to receive an additional fee of $2,500 per year; and
- $375 per meeting for service on the Hedging and Acquisitions Committee, with the Chairman of the Hedging and Acquisition Committee being entitled to receive an additional fee of $2,500 per year.

The cash fees paid to our non-employee Directors for their services in 2005 are as follows: Mr. Chitwood received – $23,125; Mr. Shrader – $23,750; Mr. Poage – $27,500; and Mr. Oring – $26,875. All Directors are reimbursed for expenses incurred in connection with attending meetings.

Options

Directors who are not employees of Parallel are also eligible to participate in Parallel's 1997 Nonemployee Directors Stock Option Plan and the 2001 Nonemployee Directors Stock Option Plan. No options were granted to any of the non-employee Directors in 2004.

2004 Non-Employee Director Stock Grant Plan

On April 29, 2004, upon recommendation of the Board's Compensation Committee, our Directors approved the 2004 Non-Employee Director Stock Grant Plan, and the plan was later approved by the stockholders at our annual meeting held on June 22, 2004. Directors of Parallel who are not employees of Parallel or any of its subsidiaries are eligible to participate in the Plan.

Under the Plan, each non-employee Director is entitled to receive an annual retainer fee consisting of shares of common stock that will be automatically granted on the first day of July in each year. The actual number of shares received is determined by dividing $25,000 by the average daily closing price of the common stock on the Nasdaq Stock Market for the ten consecutive trading days commencing fifteen trading days before the first day of July of each year. Historically, Directors' fees had been paid solely in cash. However, in accordance with this plan and following approval by our stockholders, we commenced paying an annual retainer fee in July 2004 to each non-employee Director in the form of common stock having a value of $25,000.

The plan is administrated by the Compensation Committee. Although the Compensation Committee has authority to adopt such rules and regulations for carrying out the Plan as it may deem proper and in the best interests of Parallel, the Committee's administrative functions are largely ministerial in view of the Plan's explicit provisions described below, including those related to eligibility and predetermination of the timing, pricing and amount of grants. The interpretation by the Compensation Committee of any provision of the Plan is final.

The total number of shares available for grant is 116,000 shares of common stock, subject to adjustment as described below. If there is a change in the common stock by reason of a merger, consolidation, reorganization, recapitalization, stock divided, stock split, combination of shares, exchange of shares, change in corporate structure or otherwise, the aggregate number of shares available under the Plan will be appropriately adjusted in order to avoid dilution or enlargement of the rights intended to be made available under the Plan.

The Board may suspend, terminate or amend the Plan at any time or from time to time in any manner that the Board may deem appropriate; provided that, without approval of the stockholders, no revision or amendment shall change the eligibility of Directors to receive stock grants, the number of shares of common stock subject to any grants or the Plan itself, or materially increase the benefits accruing to participants under the Plan, and Plan provisions relating to the amount, price and timing of grants of stock may not be amended.

Shares acquired under the Plan are non-assignable and non-transferable other than by will or the laws of descent and distribution and may not be sold, pledged, hypothecated, assigned or transferred until the non-employee Director holding such Stock ceases to be a Director, except that the Compensation Committee may permit transfer of stock subject to the condition that the Compensation Committee receive evidence satisfactory to it that the transfer is being made for essentially estate and/or tax planning purposes or a gratuitous or donative purpose and without consideration.

The plan will remain in effect until terminated by the Board, although no additional shares of common stock may be issued after the 116,000 shares subject to the Plan have been issued.

Stock Option Plans

1992 Stock Option Plan. In May, 1992, our stockholders approved and adopted the 1992 Stock Option Plan. The 1992 Plan expired by its own terms on March 1, 2002, but remains effective only for purposes of outstanding options. The 1992 Plan provided for granting to key employees, including officers and Directors who were also key employees of Parallel, and Directors who were not employees, options to purchase up to an aggregate of 750,000 shares of common stock. Options granted under the 1992 Plan to employees are either incentive stock options or options which do not constitute incentive stock options. Options granted to nonemployee Directors are not incentive stock options.

The 1992 Plan is administered by the Board's Compensation Committee, none of whom were eligible to participate in the 1992 Plan, except to receive a one-time option to purchase 25,000 shares at the time he or she became a Director. The Compensation Committee selected the employees who were granted options and established the number of shares issuable under each option and other terms and conditions approved by the Compensation Committee. The purchase price of common stock issued under each option is the fair market value of the common stock at the time of grant.

The 1992 Plan provided for the granting of an option to purchase 25,000 shares of common stock to each individual who was a nonemployee Director of Parallel on March 1, 1992 and to each individual who became to nonemployee Director following March 1, 1992. Members of the Compensation Committee were not eligible to participate in the 1992 Plan other than to receive a nonqualified stock option to purchase 25,000 shares of common stock as described above.

An option may be granted in exchange for an individual's right and option to purchase shares of common stock pursuant to the terms of a prior option agreement. An agreement that grants an option in exchange for a prior option must provide for the surrender and cancellation of the prior option. The purchase price of common stock issued under an option granted in exchange for a prior option is determined by the Compensation Committee and may be equal to the price for which the optionee could have purchased common stock under the prior option.

At March 1, 2002, 65,000 shares of common stock remained authorized for issuance under the 1992 Plan. However, the 1992 Plan prohibited the grant of options after March 1, 2002. Consequently, no additional options are available for grant under the 1992 Plan.

At March 1, 2006, options to purchase a total of 146,750 shares of common stock were outstanding under the 1992 Plan.

1997 Nonemployee Directors Stock Option Plan. The Parallel Petroleum 1997 Non-Employee Directors Stock Option Plan was approved by our stockholders at the annual meeting of stockholders held in May, 1997. This plan provides for granting to Directors who are not employees of Parallel options to purchase up to an aggregate of 500,000 shares of common stock. Options granted under the plan will not be incentive stock options within the meaning of the Internal Revenue Code.

This Plan is administered by the Compensation Committee of the Board of Directors. The Compensation Committee has sole authority to select the nonemployee Directors who are to be granted options; to establish the number of shares which may be issued to nonemployee Directors under each option; and to prescribe the terms and conditions of the options in accordance with the plan. Under provisions of the plan, the option exercise price must be the fair market value of the stock subject to the option on the grant due. Options are not transferable other than by will or the laws of descent and distribution and are not exercisable after ten years from the date of grant.

The purchase price of shares as to which an option is exercised must be paid in full at the time of exercise in cash, by delivering to Parallel shares of stock having a fair market value equal to the purchase price, or a combination of cash or stock, as established by the Compensation Committee.

Options may not be granted under this plan after March 27, 2007. At March 1, 2006, options to purchase a total of 355,000 shares of common stock were outstanding under this plan.

At March 1, 2006, options to purchase 17,500 shares of common stock were available for future grants under this plan.

1998 Stock Option Plan. In June, 1998, our stockholders adopted the 1998 Stock Option Plan. The 1998 Plan provides for the granting of options to purchase up to 850,000 shares of common stock. Stock options granted under the 1998 Plan may be either incentive stock options or stock options which do not constitute incentive stock options.

The 1998 Plan is administered by the Compensation Committee of the Board of Directors. Members of the Compensation Committee are not eligible to participate in the 1998 Plan. Only employees are eligible to receive options under the 1998 Plan. The Compensation Committee selects the employees who are granted options and establishes the number of shares issuable under each option.

Options granted to employees contain terms and conditions that are approved by the Compensation Committee. The Compensation Committee is empowered and authorized, but is not required, to provide for the exercise of options by payment in cash or by delivering to Parallel shares of common stock having a fair market value equal to the purchase price, or any combination of cash or common stock. The purchase price of common stock issued under each option must not be less than the fair market value of the common stock at the time of grant. Options granted under the 1998 Plan are not transferable other than by will or the laws of descent and distribution and are not exercisable after ten years from the date of grant.

Options may not be granted under the 1998 Plan after March 11, 2008. At March 1, 2006, options to purchase a total of 218,500 shares of common stock were outstanding under this plan.

At March 1, 2006, there were no available options to purchase shares of common stock for future grant under the 1998 Stock Option Plan.

2001 Nonemployee Directors Stock Option Plan. The Parallel Petroleum 2001 Non-employee Directors Stock Option Plan was approved by our stockholders at the annual meeting of stockholders held in June, 2001. This plan provides for granting to Directors who are not employees of Parallel options to purchase up to an aggregate of 500,000 shares of common stock. Options granted under the plan will not be incentive stock options within the meaning of the Internal Revenue Code.

This Plan is administered by the Compensation Committee of the Board of Directors. The Compensation Committee has sole authority to select the nonemployee Directors who are to be granted options; to establish the number of shares which may be issued to nonemployee Directors under each option; and to prescribe such terms and conditions as the Committee prescribes from time to time in accordance with the plan. Under provisions of the plan, the option exercise price must be the fair market value of the stock subject to the option on the grant date. Options are not transferable other than by will or the laws of descent and distribution and are not exercisable after ten years from the date of grant.

The purchase price of shares as to which an option is exercised must be paid in full at the time of exercise in cash, by delivering to Parallel shares of stock having a fair market value equal to the purchase price, or a combination of cash or stock, as established by the Compensation Committee.

Options may not be granted under this plan after May 2, 2011. At March 1, 2006, options to purchase 450,000 shares of common stock were outstanding under this plan.

At March 1, 2006, there were no available options to purchase shares of common stock for future grant under the 2001 Nonemployee Directors Stock Option Plan.

Employee Stock Option Plan. In June, 2001, our Board of Directors adopted the Parallel Petroleum Employee Stock Option Plan. This plan authorized the grant of options to purchase up to 200,000 shares of common stock, or less than 1.00% of our outstanding shares of common stock. Directors and officers are not eligible to receive options under this plan. Only employees are eligible to receive options. Stock options granted under this plan are not incentive stock options.

This plan was implemented without stockholder approval.

The employee Stock Option Plan is administrated by the Compensation Committee of the Board of Directors. The Compensation Committee selects the employees who are granted options and establishes the number of shares issuable under each option.

Options granted to employees contain terms and conditions that are approved by the Compensation Committee. The Compensation Committee is empowered and authorized, but is not required, to provide for the exercise of options by payment in cash or by delivering to Parallel shares of common stock having a fair market value equal to the purchase price, or any combination of cash or common stock. The purchase price of common stock issued under each option must not be less than the fair market value of the common stock at the time of grant. Options granted under this plan are not transferable other than by will or the laws of descent and distribution.

The Employees Stock Option Plan will expire on June 20, 2011. Unless some of the options that have been granted under the plan are forfeited and again become available for future grant, no additional options may be granted under this plan.

At March 1, 2006, options to purchase 200,000 shares of common stock were outstanding under this plan.

Section 408(k) Retirement Plan

Until December 31, 2004, Parallel maintained under Section 408(k) of the Internal Revenue Code a combination simplified employee pension and individual retirement account plan for eligible employees. Generally, eligible employees included all employees who were at least twenty-one years of age.

Effective January 1, 2005, the 408(k) plan was terminated and replaced with a new retirement plan under Section 401(K) of the Internal Revenue Code, as described below.

Contributions to employee SEP accounts were made at the discretion of Parallel, as authorized by the Compensation Committee of the Board of Directors. Although the percentage of contributions were permitted to vary from time to time, the same percentage contribution was required to be made for all participating employees. Parallel was not required to make annual contributions to the SEP accounts. Under the prototype plan adopted by Parallel, all of the SEP contributions were required to be made to SEP/IRAs maintained with the sponsor of the plan, a national investment banking firm. All contributions to employees' accounts vested immediately and became the property of each employee at the time of contribution, including employer contributions, income-deferral contributions and IRA contributions. Generally, earnings on contributions to an employee's SEP/IRA account are not subject to federal income tax until withdrawn.

In addition to receiving SEP contributions made by Parallel, employees were permitted to make individual annual IRA contributions of up to the maximum of $13,000. Maximum total contribution for Parallel and Parallel's employees can be no more than $41,000. In addition to the annual salary deferral limit stated above, employees who reach age 50 or older during a calendar year can elect to take advantage of a catch-up salary deferral contribution; eligible participants can increase their salary deferral by $3,000 for the year 2005. Each employee is responsible for the investment of funds in his or her own SEP/IRA and can select investments offered through the sponsor of the plan.

Distributions could be taken by employees at any time and must commence by April 1st following the year in which the employee attains age 70½.

Parallel made matching contributions to employee accounts in an amount equal to the contribution made by each employee, subject to a maximum of 6% of each employee's salary during any calendar year. During 2004, Parallel contributed an aggregate of $132,618 to the accounts of 28 employee participants. Of this amount, $15,000 was allocated to Mr. Oldham's account; $8,400 was allocated to Mr. Bayley's account; $8,400 was allocated to Mr. Rutherford's account; $13,560 to Mr. Tiffin's account; and $8,760 to Mr. Foster's account.

Section 401(k) Retirement Plan

Effective January 1, 2005, Parallel adopted a retirement plan (the "Plan") which qualifies under Section 401(k) of the Internal Revenue Code. The Plan is designed to provide eligible employees with an opportunity to save for retirement on a tax-deferred basis. A third party acts as the Plan's administrator and is responsible for the day-to-day administration and operation of the Plan. The Plan is maintained on a yearly basis beginning on January 1 and ending on December 31 of each year.

Each employee is eligible to participate in the Plan as of the date of his or her employment. An employee may elect to have his or her compensation reduced by a specific percentage or dollar amount and have that amount contributed to the Plan as a salary deferred contribution. A Plan participant's aggregate salary deferred contributions for a plan year may not exceed certain statutory dollar limits, which for 2005 is $14,000. In addition to the annual salary deferral limit, employees who reach age 50 or older during a calendar year can elect to take advantage of a catch-up salary deferral contribution; eligible participants can increase their salary deferral by $4,000 for the year 2005.The amount deferred by a Plan participant, and any earnings on that amount, will not be subject to income tax until actually distributed to such participant.

Each year, in addition to salary deferrals made by a participant, Parallel may contribute to the Plan matching contributions and discretionary profit sharing contributions. Matching contributions, if made, will equal a uniform percentage of a participant's salary deferrals. For 2005, the Compensation Committee established an annual profit sharing contribution of 3% and a matching contribution in an amount not to exceed 3% of a participant's annual salary. Each participant will share in discretionary profit sharing contributions, if any, regardless of the amount of service completed by the participant during the applicable plan year.

Each participant may direct the investment of his or her interest in the Plan under established investment direction procedures setting forth the investment choices available to the participants. Each participant will be entitled to all of the participant's account under the Plan upon retirement after age 65. Each participant is at all times 100% vested in amounts attributed to the participant's salary deferrals and to matching contributions and discretionary profit sharing contributions made by Parallel. The Plan contains special provisions relating to disability and death benefits.

Participants may borrow from their respective Plan accounts, subject to the Plan administrator's determination that the participant submitting an application for a loan meets the rules and requirements set forth in the written loan program established by Parallel. Parallel has the right to amend the Plan at any time. However, no amendment may authorize or permit any part of the Plan assets to be used for purposes other than the exclusive benefit of participants or their beneficiaries.

Parallel made matching contributions to employee accounts in an amount equal to the contribution made by each employee, subject to a maximum of 6% of each employee's salary during any calendar year. During 2005, Parallel contributed an aggregate of $168,195 to the accounts of 36 employee participants. Of this amount, $16,500 was allocated to Mr. Oldham's account; $9,220 was allocated to Mr. Bayley's account; $9,220 was allocated to Mr. Rutherford's account; $14,500 to Mr. Tiffin's account; and $9,272 to Mr. Foster's account.

Item 12. Security Ownership of Certain Benefical Owners and Management and Related Stockholder Matters

This table shows information as of March 14, 2006 about the beneficial ownership of common stock by: (1) each person known by us to own beneficially more than five percent of our outstanding common stock; (2) the executive officers named in the Summary Compensation Table in this report; (3) each director of Parallel; and (4) all of Parallel's executive officers and directors as a group.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership[1]	Percent of Class[2]
Thomas R. Cambridge 2201 Civic Circle, Suite 216 Amarillo, Texas 79109	1,041,545[3]	2.96%
Dewayne E. Chitwood 400 Pine St., Suite 700 Abilene, Texas 79601	1,374,894[4]	3.93%
Larry C. Oldham 1004 N. Big Spring, Suite 400 Midland, Texas 79701	889,590[5]	2.55%
Martin B. Oring 10817 Grande Blvd. West Palm Beach, Florida 33417	223,787[6]	*
Ray M. Poage 4711 Meandering Way Colleyville, Texas 76034	78,189[7]	*
Jeffrey G. Shrader 801 S. Filmore, Suite 600 Amarillo, Texas 79105	133,121	*
Eric A. Bayley 1004 N. Big Spring, Suite 400 Midland, Texas 79701	203,490[8]	*
John S. Rutherford 1004 N. Big Spring, Suite 400 Midland, Texas 79701	166,300[9]	*
Donald E.Tiffin 1004 N. Big Spring, Suite 400 Midland, Texas 79701	63,265[10]	*
Steven D. Foster 1004 N. Big Spring, Suite 400 Midland, Texas 79701	46,000[11]	*
All Executive Officers and Directors as a Group (10 persons)	4,220,181[12]	13.57%

*Less than one percent.

(1) Unless otherwise indicated, all shares of common stock are held directly with sole voting and investment powers.

(2) Securities not outstanding, but included in the beneficial ownership of each such person, are deemed to be outstanding for the purpose of computing the percentage of outstanding securities of the class owned by such person, but are not deemed to be outstanding for the purpose of computing the percentage of the class owned by any other person. Shares of common stock that may be acquired within sixty days upon exercise of outstanding stock options and warrants or upon conversion of preferred stock are deemed to be outstanding.

(footnotes continued on following page)

(3) Includes 741,545 shares of common stock held indirectly through Cambridge Collateral Services, Ltd., a limited partnership of which Mr. Cambridge and his wife are the general partners. Also included are 300,000 shares of common stock underlying presently exercisable stock options held by Mr. Cambridge.
(4) Includes 1,246,773 shares of common stock held directly by Wes-Tex Drilling Company, L.P., a limited partnership. In his capacity as president, chief executive officer and a manager of Wes-Tex Holdings, LLC, the general partner of Wes-Tex Drilling Company, L.P., Mr. Chitwood may be deemed to have shared voting and investment powers with respect to such shares. Also included are 20,000 shares of common stock held by the Estate of Myrle Greathouse (the "Estate"). Mr. Chitwood is the executor (but not a beneficiary) of the Estate, and in his capacity as executor, Mr. Chitwood may also be deemed to have shared voting and investment powers with respect to the shares of common stock beneficially owned by the Estate. However, Mr. Chitwood disclaims beneficial ownership of all shares of common stock held by Wes-Tex Drilling Company, L.P., and the Estate. Also included are 100,000 shares of common stock underlying presently exercisable stock options held by Mr. Chitwood.
(5) Includes 400,000 shares of common stock held indirectly through Oldham Properties, Ltd., a limited partnership. Also included are 46,000 shares of common stock underlying presently exercisable stock options held by Mr. Oldham.
(6) Of the total number of shares shown, 24,000 shares are held directly by Mr. Oring's wife; 100,000 shares may be acquired by Mr. Oring upon exercise of stock options held by Mr. Oring; and 91,666 shares may be acquired upon exercise of a stock purchase warrant.
(7) Includes 50,000 shares that may be acquired upon exercise of a presently exercisable stock option.
(8) Includes 125,000 shares of common stock underlying presently exercisable stock options. A total of 6,790 shares of common stock are held indirectly by Mr. Bayley through individual retirement accounts and Parallel's 408(K) Plan.
(9) Includes 93,750 shares of common stock underlying presently exercisable stock options. Also included are 7,550 shares held indirectly by Mr. Rutherford through his 408(k) Plan.
(10) Of the total number of shares shown 9,350 shares are held indirectly through Mr. Tiffin's individual retirement account.
(11) Includes 400 shares of common stock held directly by Mr. Foster's wife and 9,000 shares held in his 408(K) Plan.
(12) Includes 1,505,416 shares of common stock underlying stock options and warrants that are presently exercisable or that become exercisable within sixty days and 628,569 shares of common stock that may be acquired upon conversion of 220,000 shares of preferred stock.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires Parallel's Directors and officers to file periodic reports with the Securities and Exchange Commission. These reports show the Directors' and officers' ownership and the changes in ownership, of Parallel's common stock and other equity securities. To our knowledge, all Section 16(a) filing requirements were complied with during 2004.

Item 13. Certain Relationships and Related Transactions

Mr. Chitwood, a director of Parallel, has been the Chief Executive Officer of Wes-Tex Drilling Company, L.P. since January 30, 2001. He was appointed to Parallel's Board on December 19, 2000 to fill a vacancy created by the death of a former director of Parallel. The former director was also the sole owner of Wes-Tex Drilling Company; L.P. acquired an undivided working interest from Parallel in an oil and gas prospect located in Howard County, Texas. Since then, Wes-Tex has participated with us and other interest owners in the drilling and development of this prospect. Wes-Tex has participated in these operations under standard form operating agreements on the same or similar terms afforded by Parallel to nonaffiliated third parties. We invoice all working interest owners, including Wes-Tex, on a monthly basis, without interest, for their pro rata share of lease acquisition, drilling and operating expenses. During 2005, we billed Wes-Tex $3,906 for its proportionate share of lease operating expenses incurred on properties we operate and Wes-Tex paid us $6,999 for these drilling and development expenses, which included $3,099 attributable to expenses billed to Wes-Tex in 2004. The largest amount owed to us by Wes-Tex at any on time during 2005 for its share of lease operating expenses was $3,906. At December 31, 2005, no amounts were owed by us to Wes-Tex for these expenses. During 2005, we disbursed $7,672 to Wes-Tex in payment of revenues attributable to Wes-Tex's pro rata share of the proceeds from sales of oil and gas produced from properties in which Wes-Tex and Parallel owned interests. Also, in 2005 we disbursed to Wes-Tex approximately $140,000 in payment of net proceeds attributable to Wes-Tex's pro rata share of proceeds from the sale of non-strategic properties in Howard County, Texas in which Wes-Tex owned a working interest. Mr. Chitwood is not an owner of Wes-Tex and has no interest in these transactions other than in his capacity as an officer of Wes-Tex.

During 2005, Cambridge Production, Inc. a corporation owned by Mr. Cambridge, served as operator of 2 wells on oil and gas leases in which we acquired a working interest in 1984. Generally, the operator of a well is responsible for the day to day operations on the lease, overseeing production, employing field personnel, maintaining production and other records, determining the location and timing of drilling of wells, administering gas contracts, joint interest billings, revenue distribution, making various regulatory filings, reporting to working interest owners and other matters. During 2005, Cambridge Production billed us $19,610 for our pro rata share of lease operating expenses and drilling and workover expenses. The largest amount we owed Cambridge Production at any one time during 2005 was $3,915. At December 31, 2005, no amounts were owed by us to Cambridge Production for these expenses. Our pro rata share of oil and gas sales during 2005 from the wells operated by Cambridge Production was $160,982. Cambridge Production's billings to Parallel are made monthly on the same basis as all other working interest owners in the wells.

Cambridge Partnership, Ltd., a limited partnership controlled by Mr. Cambridge, acquired an undivided working interest in 1999 from Parallel in an oil and gas prospect located in south Texas. The interest was acquired on the same terms as all other unaffiliated working interest owners. Since then, Cambridge Partnership, Ltd. has participated with us in the drilling and development of this prospect. Cambridge Partnership, Ltd. has participated in these operations under standard form operating agreements on the same or similar terms afforded by Parallel to nonaffiliated third parties. Although Parallel is not the operator of this project, we invoice Cambridge Partnership, Ltd., on a monthly basis, without interest, for its pro rata share of operating expenses. During 2005, we billed Cambridge Partnership, Ltd. $1,984 for its proportionate share of lease operating expenses incurred on properties we administer and Cambridge Partnership, Ltd. paid us $2,690 for these drilling and development expenses, which included $850 attributable to expenses billed to Cambridge Partnership, Ltd. in 2004. The largest amount owed to us by Cambridge Partnership, Ltd. at any one time during 2005 for its share of lease operating expenses was $319. At December 31, 2005 Cambridge Partnership, Ltd. owed us $144 for these expenses. During 2005, we disbursed $6,220 to Cambridge Partnership, Ltd. in payment of revenues attributable to its pro rata share of the proceeds from sales of oil and gas produced from properties in which Cambridge Partnership, Ltd. and Parallel owned interests.

Cambridge Production, Inc. maintains an office in Amarillo, Texas from which Mr. Cambridge performs his duties and services as Chairman of the Board and as geological consultant to Parallel. We reimburse Cambridge Production, Inc. $3,000 per month for office and administrative expenses incurred on behalf of Parallel. During 2005 we reimbursed Cambridge Production, Inc. a total of $36,000.

In December, 2001, and prior to his employment with Parallel, Donald E. Tiffin, our Chief Operating Officer, received from an unaffiliated third party a 3% working interest in the Diamond M Project in Scurry County, Texas for services rendered in connection with assembling the project. In August, 2002, shortly after his employment with Parallel, and due to the personal financial exposure in the Diamond M Project and to prevent the interest from being acquired by a third party, Mr. Tiffin assigned two-thirds of his ownership interest in the project to Parallel at no cost, leaving him with a 1% working interest. Parallel acquired its initial interest in the Diamond M Project from the same third party in December, 2001, but did not become operator of the project until March 1, 2003. As with other nonaffiliated interest owners, we invoice Mr. Tiffin on a monthly basis, without interest, for his share of drilling, development and lease operating expenses. During 2005, we billed Mr. Tiffin a total of $80,825 for his proportionate share of capital expenditures and lease operating expenses, and Mr. Tiffin paid us $71,982 for these drilling and development expenses, which included $2,759 attributable to expenses billed to Mr. Tiffin in 2004. During 2005, we disbursed to Mr. Tiffin $54,841 in oil and gas revenues related to his interest in this project. The largest aggregate amount outstanding and owed to us by Mr. Tiffin at any one time during 2005 was $18,804. At December 31, 2005, Mr. Tiffin owed us approximately $11,603.

We believe the transactions described above were made on terms no less favorable than if we had entered into the transactions with an unrelated party.

Item 14. Principal Accountant Fees and Services

KPMG LLP audited our consolidated financial statements for the year ended December 31, 2002 and for the prior eighteen years. However, as described under Item 9 of this Annual Report on Form 10-K, KPMG resigned in December 2003. Prior to KPMG's resignation KPMG provided audit and tax services in 2003. In January 2004, we engaged BDO Seidman, LLP as our independent auditors.

The audit committee had not, as of the time of filing this Annual Report on Form 10-K with the Securities and Exchange Commission, adopted policies and procedures for pre-approving audit or permissible non-audit services performed by our independent auditors. Instead, the audit committee as a whole has pre-approved all such services. In the future, our audit committee may approve the services of our independent auditors pursuant to pre-approval policies and procedures adopted by the Audit Committee, provided the policies and procedures are detailed as to the particular service, the Audit Committee is informed of each service, and such policies and procedures do not include delegation of the Audit Committee's responsibilities to Parallel's management.

The aggregate fees for professional services rendered by BDO in 2005 and 2004 were:

Types of Fees	**2005**	2004
	(dollars in thousands)	
Audit fees	**$ 383**(1)	$ 564(2)
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	**$ 383**	$ 564

(1) Such amount includes $160,000 for professional services in connection with the audit of the internal control over financial reporting with Section 404 of the Sarbanes-Oxley of 2002. This amount includes associated expenses in the amount of approximately $20,000.

(2) Such amount includes $320,000 for professional services in connection with the audit of the internal control over financial reporting under Section 404 of the Sarbanes-Oxley of 2002. This amount includes associated expenses in the amount of approximately $41,000.

We retained a third party to assist Parallel's management in the Sarbanes-Oxley 404 readiness and assessment of internal control over financial reporting. Their aggregate fees for services provided in connection with the internal control over financial reporting 2005 and 2004 were approximately $85,000 and $338,000, including associated expenses.

In the above table, "audit fees" are fees we paid for professional services for the audit of our consolidated financial statements included in Form 10-K and review of consolidated financial statements included in Form 10-Qs, or for services that are normally provided by the accountant in connection with statutory and regulatory filings or engagements and fees for Sarbanes-Oxley 404 audit work; "audit-related fees" are fees billed for assurance and related services (such as due diligence services) that are reasonably related to the performance of the audit or review of our consolidated financial statements; "tax fees" are fees for tax compliance, advice and planning; and "all other fees" are fees billed to Parallel for any services not included in the first three categories.

It is estimated that personnel other than full time permanent employees of BDO performed 70% of the total hours expended to audit Parallel's consolidated financial statements.

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

(a)(1) and (a)(2) Financial Statement and Financial Statement Schedules

For a list of Consolidated Financial Statements and Schedules, see "Index to the Consolidated Financial Statements" on page 80 [F-1], and incorporated herein by reference.

(a)(3) Exhibits

See Item 15(b) below.

(b) Exhibits:

A list of exhibits to this Annual Report on Form 10-K is set forth below.

No.	Description of Exhibit
3.1	Certificate of Incorporation of Registrant (Incorporated by reference to Exhibit 3.1 to Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2004)
3.2	Bylaws of Registrant (Incorporated by reference to Exhibit 3 of the Registrant's Form 8-K, dated October 9, 2000, as filed with the Securities and Exchange Commission on October 10, 2000)
3.3	Certificate of Formation of Parallel, L.L.C. (Incorporated by reference to Exhibit No. 3.3 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.4	Limited Liability Company Agreement of Parallel, L.L.C. (Incorporated by reference to Exhibit No. 3.4 of the Registrant's Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.5	Certificate of Limited Partnership of Parallel, L.P. (Incorporated by reference to Exhibit No. 3.5 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.6	Agreement of Limited Partnership of Parallel, L.P. (Incorporated by reference to Exhibit No. 3.6 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.1	Certificate of Designations, Preferences and Rights of Serial Preferred Stock – 6% Convertible Preferred Stock (Incorporated by reference to Exhibit 4.1 of Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2004)
4.2	Certificate of Designation, Preferences and Rights of Series A Preferred Stock (Incorporated by reference to Exhibit 4.2 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)
4.3	Rights Agreement, dated as of October 5, 2000, between the Registrant and Computershare Trust Company, Inc., as Rights Agent (Incorporated by reference to Exhibit 4.3 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)
4.4	Form of Indenture relating to senior debt securities of the Registrant (Incorporated by reference to Exhibit No. 4.4 of the Registrant's Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.5	Form of Indenture relating to subordinated debt securities of the Registrant (Incorporated by reference to Exhibit No. 4.5 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.6	Form of common stock certificate of the Registrant (Incorporated by reference to Exhibit No. 4.6 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.7	Warrant Purchase Agreement, dated November 20, 2001, between the Registrant and Stonington Corporation (Incorporated by reference to Exhibit 4.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
4.8	Warrant Purchase Agreement, dated December 23, 2003, between the Registrant and Stonington Corporation (Incorporated by reference to Exhibit 4.8 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)

Executive Compensation Plans and Arrangements (Exhibit No.'s 10.1 through 10.8):

10.1 1992 Stock Option Plan (Incorporated by reference to Exhibit 10.1 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)

10.2 Merrill Lynch, Pierce, Fenner & Smith Incorporated Prototype Simplified Employee Pension Plan (Incorporated by reference to Exhibit 10.6 of the Registrant's Form 10-K for the fiscal year ended December 31, 1995)

10.3 Non-Employee Directors Stock Option Plan (Incorporated by reference to Exhibit 10.3 of the Registrant's Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2005)

10.4 1998 Stock Option Plan (Incorporated by reference to Exhibit 10.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 1998)

10.5 Form of Incentive Award Agreements, dated December 12, 2001, between the Registrant and Thomas R. Cambridge, Larry C. Oldham, Eric A. Bayley and John S. Rutherford granting 2,394 Unit Equivalent Rights to Mr. Cambridge; 9,564 Unit Equivalent Rights to Mr. Oldham; 2,869 Unit Equivalent Rights to Mr. Bayley; and 7,173 Unit Equivalent Rights to Mr. Rutherford (Incorporated by reference to Exhibit 10.8 of Form 10-K of the Registrant for the fiscal year ended December 31, 2001)

10.6 2001 Non-Employee Directors Stock Option Plan (Incorporated by reference to Exhibit 10.7 of the Registrant's Form 10-Q Report for the fiscal quarter ended March 31, 2004)

10.7 2004 Non-Employee Director Stock Grant Plan (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated September 22, 2004)

10.8 Incentive and Retention Plan (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated September 23, 2004 and filed with the Securities and Exchange Commission on September 29, 2004)

10.9 Certificate of Formation of First Permian, L.L.C. (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated June 30, 1999)

10.10 Limited Liability Company Agreement of First Permian, L.L.C. (Incorporated by reference to Exhibit 10.2 of the Registrant's Form 8-K Report dated June 30, 1999)

10.11 Amended and Restated Limited Liability Company Agreement of First Permian, L.L.C. dated as of May 31, 2000 (Incorporated by reference to Exhibit 10.16 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)

10.12 Credit Agreement, dated June 30, 1999, by and among First Permian, L.L.C., Parallel Petroleum Corporation, Baytech, Inc., and Bank One, Texas, N.A. (Incorporated by reference to Exhibit 10.6 of the Registrant's Form 8-K Report dated June 30, 1999)

10.13 Limited Guaranty, dated June 30, 1999, by and among First Permian, L.L.C., Parallel Petroleum Corporation and Bank One, Texas, N.A. (Incorporated by reference to Exhibit 10.7 of the Registrant's Form 8-K Report dated June 30, 1999)

10.14 Second Restated Credit Agreement, dated October 25, 2000, among First Permian, L.L.C., Bank One, Texas, N.A., and Bank One Capital Markets, Inc. (Incorporated by reference to Exhibit 10.22 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)

10.15 Loan Agreement, dated as of January 25, 2002, between the Registrant and First American Bank, SSB (Incorporated by reference to Exhibit 10.25 of Form 10-K of the Registrant for the fiscal year ended December 31, 2001)

10.16 Purchase and Sale Agreement, dated as of November 27, 2002, among JMC Exploration, Inc., Arkoma Star L.L.C., Parallel, L.P. and Texland Petroleum, Inc. (Incorporated by reference to Exhibit 10.1 of Form 8-K of the Registrant, dated December 20, 2002)

10.17 First Amended and Restated Credit Agreement, dated December 20, 2002, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, Western National Bank and BNP Paribas (Incorporated by reference to Exhibit 10.2 of Form 8-K of the Registrant, dated December 20, 2002)

10.18 Guaranty dated December 20, 2002, between Parallel, L.L.C. and First American Bank, SSB, as Agent (Incorporated by reference to Exhibit 10.3 of Form 8-K of the Registrant, dated December 20, 2002)

10.19 First Amendment to First Amended and Restated Credit Agreement, dated as of September 12, 2003, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, Western National Bank, and BNP Paribas (Incorporated by reference to Exhibit 10.29 of Form 10-Q of the Registrant for the quarter ended September 30, 2003)

10.20 Second Amendment and Restated Credit Agreement, dated September 27, 2004, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, BNP Paribas, Citibank, F.S.B. and Western National Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated September 27, 2004 and filed with the Securities and Exchange Commission on October 1, 2004)

10.21 Agreement of Limited Partnership of West Fork Pipeline Company LP (Incorporated by reference to Exhibit 10.21 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)

10.22 First Amendment to Second Amended and Restated Credit Agreement, dated as of December 27, 2004, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, BNP Paribas, Citibank, F.S.B. and Western National Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated December 30, 2004 and filed with the Securities and Exchange Commission on December 30, 2004)

10.23 Second Amendment to Second Amended and Restated Credit Agreement, dated as of April 1, 2005, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, BNP Paribas, Citibank, F.S.B. and Western National Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated April 4, 2005 and filed with the Securities and Exchange Commission on April 8, 2005)

10.24 Third Amendment to Second Amended and Restated Credit Agreement (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated October 4, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.25 Purchase and Sale Agreement, dated as of October 14, 1005, among Parallel, L.P., Lynx Production Company, Inc., Elton Resources, Inc., Cascade Energy Corporation, Chelsea Energy, Inc., William P. Sutter, Trustee, William P. Sutter Trust, J. Leroy Bell, E. L. Brahaney, Brent Beck, Cavic Interests, LLC and Stanley Talbott (Incorporated by reference to Exhibit 10.2 of the Registrant's Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.26 Ancillary Agreement to Purchase and Sale Agreement, dated October 14, 2005, between Parallel, L.P. and Lynx Production Company, Inc. (Incorporated by reference to Exhibit 10.3 of the Registrant's Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.27 Guarantee of Parallel, L.P., dated October 13, 2004 (Incorporated by reference to Exhibit 10.4 of the Registrant's Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.28 ISDA Master Agreement, dated as of October 13, 2005, between Parallel, L.P. and Citibank, N.A. (Incorporated by reference to Exhibit 10.5 of the Registrant's Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.29 Third Amended and Restated Credit Agreement, dated as of December 23, 2005, among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C. and Citibank Texas, N.A., BNP Paribas, CitiBank F.S.B., Western National Bank, Compass Bank, Comerica Bank, Bank of Scotland and Fortis Capital Corp. (Incorporated by reference to Exhibit No. 10.1 of the Registrant's Form 8-K Report, dated December 23, 2005, as filed with the Securities and Exchange Commission on December 30, 2005)

10.30 Second Lien Term Loan Agreement, dated November 15, 2005, among Parallel Petroleum Corporation, Parallel, L.P., BNP Paribas and Citibank Texas, N.A. (Incorporated by reference to Exhibit No. 10.4 of the Registrant's Form 8-K Report, dated November 15, 2005, as filed with the Securities and Exchange Commission on November 21, 2005)

10.31 Intercreditor and Subordination Agreement, dated November 15, 2005, among Citibank Texas, N.A., BNP Paribas, Parallel Petroleum Corporation, Parallel, L.P. and Parallel, L.L.C. (Incorporated by reference to Exhibit No. 10.5 of the Registrant's Form 8-K Report, dated November 15, 2005, as filed with the Securities and Exchange Commission on November 21, 2005)

14 Code of Ethics (Incorporated by reference to Exhibit No. 14 of the Registrant's Form 10-K Report for the fiscal year ended December 31, 2003 and filed with the Securities and Exchange Commission on March 22, 2004)

21 Subsidiaries (Incorporated by reference to Exhibit No. 21 of the Registrant's Form 10-K Report for the fiscal year ended December 31, 2003 and filed with the Securities and Exchange Commission on March 22, 2004)

*23.1 Consent of BDO Seidman, LLP

*23.2 Consent of Cawley Gillespie & Associates, Inc. Independent Petroleum Engineers

*31.1 Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*31.2 Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*32.1 Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*32.2 Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Filed herewith.

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

All schedules are omitted, as the required information is inapplicable or the information is presented in the Consolidated Financial Statements or related notes.

Report of Independent Registered Public Accounting Firm

Board of Directors
Parallel Petroleum Corporation
Midland, Texas

We have audited the accompanying consolidated balance sheets of Parallel Petroleum Corporation as of December 31, 2005 and 2004 and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 18 to the consolidated financial statements, the Company has restated its 2004 consolidated financial statements.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Parallel Petroleum Corporation at December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Parallel Petroleum Corporation's internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 10, 2006, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an adverse opinion on the effectiveness of the Company's internal control over financial reporting.

BDO Seidman, LLP
Houston, Texas
March 10, 2006

Consolidated Balance Sheets

December 31, 2005 and 2004 (dollars in thousands)	2005	2004
Assets		
Current assets:		*(restated)*
Cash and cash equivalents	$ 6,418	$ 4,781
Accounts receivable:		
Oil and gas	13,183	6,642
Other, net of allowance for doubtful account of $9	877	389
Affiliates	12	7
	14,072	7,038
Other current assets	2,364	179
Deferred tax asset	5,241	2,531
Total current assets	28,095	14,529
Property and equipment, at cost:		
Oil and gas properties, full cost method (including $19,869 and $9,526 not subject to depletion)	303,819	229,245
Other	2,404	2,062
	306,223	231,307
Less accumulated depreciation, depletion and amortization	(90,826)	(78,782)
Net property and equipment	215,397	152,525
Restricted cash	2,640	2,287
Investment in Westfork Pipeline Companies	3,326	595
Other assets, net of accumulated amortization of $901 and $581	3,550	735
	$ 253,008	$ 170,671
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 10,841	$ 5,568
Asset retirement obligations	214	150
Derivative obligations	16,607	7,965
Total current liabilities	27,662	13,683
Revolving credit facility	50,000	79,000
Term loan	50,000	—
Asset retirement obligations	2,281	1,982
Derivative obligations	25,527	9,525
Deferred tax liability	8,036	6,487
Total long-term liabilities	135,844	96,994
Commitments and contingencies (Note 15)		
Stockholders' equity:		
Series A preferred stock – par value $0.10 per share, authorized 50,000 shares	—	—
Preferred stock – $0.60 cumulative convertible preferred stock – par value of $0.10 per share, (liquidation preference of $10 per share) authorized 10,000,000 shares, issued and outstanding 0 and 950,000	—	95
Common stock – par value $0.01 per share, authorized 60,000,000 shares, issued and outstanding 34,748,916 and 25,439,292	347	254
Additional paid-in capital	78,699	48,328
Retained earnings	16,899	18,759
Accumulated other comprehensive loss	(6,443)	(7,442)
Total stockholders' equity	89,502	59,994
	$ 253,008	$ 170,671

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

Years ended December 31, 2005, 2004, 2003 (dollars in thousands, except per share data)	2005	2004	2003
Oil and natural gas revenues:		*(restated)*	
Oil and natural gas sales	**$ 66,150**	$ 35,837	$ 33,855
Cost and expenses:			
Lease operating expense	**9,947**	7,373	6,458
Production taxes	**4,102**	2,108	1,946
General and administrative	**6,712**	5,378	4,344
Depreciation, depletion and amortization	**12,044**	8,712	8,390
Total costs and expenses	**32,805**	23,571	21,138
Operating income	**33,345**	12,266	12,717
Other income (expense), net:			
Change in fair market value of derivative instruments	**(31,669)**	(5,726)	(22)
Gain (loss) on ineffective portion of hedges	**(137)**	(240)	191
Interest and other income	**167**	189	116
Interest expense	**(4,780)**	(2,732)	(2,048)
Other expense	**(102)**	(324)	(259)
Equity in loss of Westfork Pipeline Companies	**(89)**	—	—
Total other income (expense), net	**(36,610)**	(8,833)	(2,022)
Income (loss) before income taxes	**(3,265)**	3,433	10,695
Income tax benefit (expense), deferred	**1,676**	(1,162)	(3,031)
Income (loss) before cumulative effect of change in accounting principle	**(1,589)**	2,271	7,664
Cumulative effect on prior years of a change in accounting principle, net of tax of $32	**—**	—	(62)
Net income (loss)	**(1,589)**	2,271	7,602
Cumulative preferred stock dividend	**(271)**	(572)	(580)
Net income (loss) available to common stockholders	**$ (1,860)**	$ 1,699	$ 7,022
Net income (loss) per common share:			
Basic	**$ (0.06)**	$ 0.07	$ 0.33
Diluted	**$ (0.06)**	$ 0.07	$ 0.31

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Stockholders' Equity

Years ended December 31, 2005, 2004 and 2003

(amounts in thousands)	Preferred Stock Number of Shares	Preferred Stock Amount	Common Stock Number of Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity
Balance, January 1, 2003	975	$ 97	21,143	$ 212	$ 35,152	$ 10,038	$ —	$ 45,499
Common stock issued for cash	—	—	4,000	40	12,080	—	—	12,120
Preferred stock converted	(15)	(1)	43	1	—	—	—	—
Warrants issued for services	—	—	—	—	157	—	—	157
Options exercised, including income tax benefit of $19	—	—	31	—	57	—	—	57
Stock option expense	—	—	—	—	98	—	—	98
Changes in fair value of cash flow hedges, net of tax	—	—	—	—	—	—	(3,721)	(3,721)
Net income	—	—	—	—	—	7,602	—	7,602
Dividends on preferred stock ($0.60 per share)	—	—	—	—	—	(580)	—	(580)
Balance, December 31, 2003	960	96	25,217	253	47,544	17,060	(3,721)	61,232
Common stock issued for services	—	—	21	—	99	—	—	99
Preferred stock converted	(10)	(1)	27	—	1	—	—	—
Options exercised, including income tax benefit of $177	—	—	174	1	522	—	—	523
Deferred stock offering costs	—	—	—	—	(7)	—	—	(7)
Stock option expense	—	—	—	—	169	—	—	169
Changes in fair value of cash flow hedges, net of tax	—	—	—	—	—	—	(3,721)	(3,721)
Net income – restated	—	—	—	—	—	2,271	—	2,271
Dividends on preferred stock ($0.60 per share)	—	—	—	—	—	(572)	—	(572)
Balance, December 31, 2004 – restated	950	95	25,439	254	48,328	18,759	(7,442)	59,994
Common stock issued, net of transaction costs	—	—	5,750	58	27,686	—	—	27,744
Common stock issued for services	—	—	12	—	99	—	—	99
Preferred stock converted	(950)	(95)	2,714	27	68	—	—	—
Cashless exercise of warrants	—	—	120	1	(1)	—	—	—
Options exercised, including income tax benefit of $44	—	—	714	7	2,241	—	—	2,248
Stock option expense	—	—	—	—	278	—	—	278
Changes in fair value of cash flow hedges, net of tax	—	—	—	—	—	—	999	999
Net income (loss)	—	—	—	—	—	(1,589)	—	(1,589)
Dividends on preferred stock ($0.60 per share)	—	—	—	—	—	(271)	—	(271)
Balance, December 31, 2005	—	$ —	34,749	$ 347	$ 78,699	$ 16,899	$ (6,443)	$ 89,502

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Years ended December 31, 2005, 2004 and 2003 (in thousands)	2005	2004	2003
Cash flows from operating activities:		*(restated)*	
Net income (loss)	$ (1,589)	$ 2,271	$ 7,602
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	12,044	8,712	8,390
Accretion of asset retirement obligation	112	92	139
Deferred income taxes	(1,676)	1,162	3,031
Change in fair market value of derivative instruments	31,669	5,726	22
(Gain) loss on ineffective portion of hedges	137	240	(191)
Common stock issued in lieu of cash for directors fees	99	99	—
Stock option expense	278	169	98
Stock-based financial advisory services	—	—	157
Cumulative effect on prior years of a change in accounting principle, net of tax	—	—	62
Equity in loss of Westfork Pipeline Companies	89	—	—
Changes in assets and liabilities:			
Other assets, net	(823)	163	167
Restricted cash	(274)	—	—
Increase in accounts receivable	(7,034)	(2,112)	(783)
(Increase) decrease in other current assets	(1,187)	31	(132)
Increase in accounts payable and accrued liabilities	5,273	1,603	931
Net cash provided by operating activities	37,118	18,156	19,493
Cash flows from investing activities:			
Additions to oil and gas properties	(77,351)	(67,911)	(14,930)
Restricted cash	(79)	(2,287)	—
Proceeds from disposition of oil and gas properties	3,028	1,625	64
Additions to other property and equipment	(342)	(647)	(331)
Settlements of derivative instruments	(5,022)	—	—
Purchase of derivative instruments	(2,363)	—	—
Investment in Westfork Pipeline Companies	(2,820)	(298)	(297)
Net cash used in investing activities	(84,949)	(69,518)	(15,494)
Cash flows from financing activities:			
Net borrowing (payments) on revolving line of credit	(29,000)	39,250	(10,000)
Deferred financing costs	(1,253)	(429)	(28)
Borrowings from term loan	50,000	—	—
Proceeds from exercise of stock options	2,248	523	55
Proceeds (net) from common stock issued	27,744	—	12,120
Payment of preferred stock dividend	(271)	(572)	(580)
Deferred stock offering costs	—	(7)	—
Net cash provided by financing activities	49,468	38,765	1,567
Net increase (decrease) in cash and cash equivalents	1,637	(12,597)	5,566
Cash and cash equivalents at beginning of year	4,781	17,378	11,812
Cash and cash equivalents at end of year	$ 6,418	$ 4,781	$ 17,378
Non-cash financing and investing activities:			
Oil and gas properties asset retirement obligation	$ 251	$ 338	$ 1,075
Other transactions:			
Interest paid	$ 5,422	$ 1,708	$ 2,048

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income (Loss)

Years ended December 31, 2005, 2004 and 2003 (dollars in thousands)	2005	2004	2003
		(restated)	
Net income (loss)	$ (1,589)	$ 2,271	$ 7,602
Other comprehensive income (loss):			
Unrealized losses on derivatives	(10,980)	(14,357)	(8,336)
Reclassification adjustment for losses on derivatives included in net income	12,494	8,719	2,699
Change in fair value of cash flow hedges	1,514	(5,638)	(5,637)
Income tax benefit, deferred	(515)	1,917	1,916
Total other comprehensive income (loss)	999	(3,721)	(3,721)
Total comprehensive income (loss)	$ (590)	$ (1,450)	$ 3,881

Notes to Consolidated Financial Statements

(1) Organization, Business and Summary of Significant Accounting Policies

(a) Basis of Consolidation

The accompanying financial statements present the consolidated accounts of Parallel Petroleum Corporation, a Delaware Corporation, and its wholly owned subsidiaries, Parallel L.P. and Parallel, L.L.C (collectively "the Company" or Parallel). All significant inter-company account balances and transactions have been eliminated. The Company accounts for its interests in oil and gas joint ventures and working interests using the proportionate consolidation method. Under this method, the Company records its proportionate share of assets, liabilities, revenues and expenses.

(b) Nature of Operations

The Company's focus is on the acquisition, development and exploitation of long-lived oil and natural gas reserves and, to a lesser extent, exploration for new oil and natural gas reserves. The Company's business activities are currently carried out primarily in Texas and New Mexico. The Company's activities are focused in the Permian Basin of west Texas and New Mexico, the Fort Worth Basin of north Texas and the onshore Gulf Coast area of south Texas. The Company is actively evaluating, leasing, drilling and preparing to drill new projects located in the Cotton Valley Reef trend of east Texas and the Uinta Basin of Utah.

(c) Concentration of Credit Risk

Financial instruments that potentially expose the Company to concentrations of credit risk consist primarily of unsecured accounts receivable from unaffiliated working interest owners and crude oil and natural gas purchasers. A substantial portion of Parallel's oil and natural gas reserves are located in the Permian Basin and the Company may be disproportionately exposed to the impact of delays or interruptions of production from these wells due to mechanical problems, damages to the current producing reservoirs and significant governmental regulation, including any curtailment of production or interruption of transportation of oil or gas produced from the wells.

(d) Property and Equipment

Oil and Gas Properties

The Company uses the full cost method of accounting for its oil and gas producing activities. Accordingly, all costs associated with acquisition, exploration, and development of oil and gas reserves, including directly related overhead costs, are capitalized.

Management and service fees received for contractual arrangements, if any, are treated as reimbursement of costs, offsetting the costs incurred to provide those services. Specifically, from time to time, the Company serves as operator of its oil and gas properties in which it owns an interest. Under operating agreements naming the Company as operator, the Company is reimbursed for certain specified direct charges and overhead charges. Amounts received in reimbursement for drilling activities are applied as a reduction to Parallel's capital costs, and amounts received in reimbursement for producing activities are applied to reduce the Company's general and administrative expenses.

Depletion is provided using the unit-of-production method based upon estimates of proved oil and gas reserves with oil and gas production being converted to a common unit of measure based upon their relative energy content. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Once the assessment of unproved properties is complete and when major development projects are evaluated, the costs previously excluded from amortization are transferred to the full cost pool and amortization begins.

If the net investment in oil and gas properties in a cost center, as adjusted for asset retirement obligations, exceeds an amount equal to the sum of (1) the standardized measure of discounted future net cash flows from proved reserves (see Note 16) and (2) the lower of cost or fair market value of properties in process of development and unexplored acreage, the excess is charged to expense as additional depletion. The standardized measure is calculated using a 10% discount rate and is based on unescalated prices in effect at year-end with effect given to the Company's cash flow hedge positions.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved oil and gas reserves, in which case the gain or loss is recognized in income.

Other Property and Equipment

Maintenance and repairs are charged to operations. Renewals and betterments are capitalized to the appropriate property and equipment accounts.

Upon retirement or disposition of assets other than oil and gas properties, the cost and related accumulated depreciation are removed from the accounts with the resulting gains or losses, if any, recognized in income. Depreciation of other property and equipment is computed using the straight-line method based on the estimated useful lives of the property and equipment.

(e) Income Taxes

The Company accounts for federal income taxes using the liability method. Under the liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Under the liability method, the effect on previously recorded deferred tax assets and liabilities resulting from a change in tax rates is recognized in earnings in the period in which the change is enacted.

(f) Investments

Investments in affiliated companies with a 20% to 50% ownership interest are accounted for on the equity basis and, accordingly, net income includes the Company's proportionate share of their income or loss.

(g) Stock-Based Compensation

Parallel accounts for its stock based compensation using the prospective method under *Statement of Financial Accounting Standards No. 123* ("SFAS 123"). Under this method, the fair values of all options granted since 2003 have been reflected as compensation expense over the periods in which the services are rendered. The following table sets forth the pro forma amounts of net income and net income per share that would have resulted if Parallel had expensed all of its stock based compensation under the fair value recognition provision of SFAS No. 123.

Year ended December 31, (in thousands, except per share data)	**2005**	2004	2003
		(restated)	
Net income (loss)	**$ (1,589)**	$ 2,271	$ 7,602
Add:			
Stock-based compensation expense for employees included in reported net income, net of related tax effects of $95, $57 and $33	**183**	112	65
Less:			
Total stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	**(610)**	(408)	(620)
Pro forma net income	**$ (2,016)**	$ 1,975	$ 7,047
Earnings (loss) per share:			
Basic – as reported	**$ (0.06)**	$ 0.07	$ 0.33
Basic – pro forma	**$ (0.07)**	$ 0.06	$ 0.30
Diluted – as reported	**$ (0.06)**	$ 0.07	$ 0.31
Diluted – pro forma	**$ (0.07)**	$ 0.05	$ 0.27

Parallel estimates the fair value of stock option grants using the Black-Scholes option pricing model. The Black-Scholes option-pricing model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable; characteristics not present in Parallel's stock option grants. Additionally, option valuation models require the input of highly subjective assumptions, including the expected volatility of the stock price. Because Parallel's employee stock options have characteristics significantly different from those of traded options and because changes in the subjective input assumptions can materially affect the fair value estimates, in Parallel's opinion, the existing models do not provide a reliable single measure of the fair value of its stock-based awards.

The assumptions used to value the stock option grants for the two years ending December 31, 2005, and 2003, (no options were granted during 2004), are as follows:

Year ended December 31,	**2005**	2003
Weighted average grant-date price	**$ 7.67**	$ 1.36
Expected volatility	**48%**	45.3%
Expected dividends	**0.00%**	0.00%
Expected term (in years)	**8**	8
Risk free rate	**4.12%**	3.7%

In 2003, the Company adopted the fair–value-based method of accounting for share based payment transactions with employees described in SFAS 123 using the prospective transition method. Parallel recognized compensation expense of $278,000, $169,000 and $98,000 in 2005, 2004 and 2003 respectively associated with its stock option grants in 2005 and 2003. The total number of options granted during 2005 and 2003 was 200,000 and 180,000 respectively.

(h) Environmental Expenditures

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed.

Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscovered unless the timing of cash payments for the liability or component are fixed or reliably determinable.

(i) Earnings Per Share

Basic earnings per share excludes any dilutive effects of option, warrants and convertible securities and is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings per share are computed similar to basic earnings per share; however, diluted earnings per share reflect the assumed conversion of all potentially dilutive securities.

The following table provides the computation of basic and diluted earnings per share for the year ended December 31:

(in thousands except per share data)	2005	2004	2003
Basic EPS Computation:		*(restated)*	
Numerator -			
Net income (loss) before cumulative effect of a change in accounting principle	$ (1,589)	$ 2,271	$ 7,664
Cumulative effect of a change in accounting principle, net of tax	—	—	(62)
	(1,589)	2,271	7,602
Preferred stock dividend	(271)	(572)	(580)
Net income (loss) available to common stockholders	$ (1,860)	$ 1,699	$ 7,022
Denominator -			
Weighted average common shares outstanding	32,253	25,323	21,264
Basic earnings (loss) per share	$ (0.06)	$ 0.07	$ 0.33
Diluted EPS Computation:			
Numerator -			
Net income (loss) before cumulative effect of a change in accounting principle	$ (1,589)	$ 2,271	$ 7,664
Cumulative effect of a change in accounting principle, net of tax	—	—	(62)
	(1,589)	2,271	7,602
Preferred stock dividend	(271)	(572)	—
Net income (loss) available to common stockholders	$ (1,860)	$ 1,699	$ 7,602
Denominator -			
Weighted average common shares outstanding	32,253	25,323	21,264
Employee stock options	—	289	150
Warrants	—	76	20
Preferred stock	—	—	2,741
Weighted average common shares for diluted earnings per share assuming conversion	32,253	25,688	24,175
Diluted earnings (loss) per share	$ (0.06)	$ 0.07	$ 0.31

For the year ended December 31, 2005, the effects of all potentially dilutive securities (including options, warrants and the "if converted" effects of convertible preferred stock) were excluded from the computation of diluted earnings per share would have been antidilutive because of the net loss. Approximately 664,000 and 1.4 million options and warrants were excluded from the computation of diluted earnings per share in 2004 and 2003, respectively, because the Company's inclusion would have resulted in antidilution. Likewise, convertible preferred shares were not treated as "if converted" for the year ended December 31, 2004, because the effects would have been antidilutive.

(j) Use of Estimates in the Preparation of Consolidated Financial Statements

Preparation of the accompanying Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. The oil and gas reserve estimates, and the related future net cash flows derived from those reserves, are used in the determination of depletion expense and the full-cost ceiling test and are inherently imprecise. Actual results could differ from those estimates.

(k) Cash Equivalents

For purposes of the statements of cash flows, the Company considers all demand deposits, money market accounts and certificates of deposit purchased with an original maturity of three months or less to be cash equivalents.

(l) Restricted Cash

Restricted cash as of December 31, 2005, includes cash held in escrow for the Harris San Andres purchase (see Note 3) aggregating approximately $2.3 million and monies placed in a certificate of deposit for a drilling bond of approximately $300,000. As of December 31, 2004, $2.1 million in cash was held in escrow for the Carm-Ann San Andres purchase.

(m) Reclassifications
Certain reclassifications have been made to 2003 and 2004 amounts to conform to the 2005 presentation.

(n) Derivative Financial Instruments
Derivative financial instruments, utilized to manage or reduce commodity price risk related to the Company's production and interest rate risk related to the Company's long-term debt, are accounted for under the provisions of SFAS No. 133, *"Accounting for Derivative Instruments and for Hedging Activities,"* and related interpretations and amendments. Under this Statement, derivatives are carried on the balance sheet at fair value. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If the derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income ("OCI") and are recognized in the statement of operations when the hedged item affects earnings. If the derivative is not designated as a hedge, changes in the fair value are recognized in other expense. Ineffective portions of changes in the fair value of cash flow hedges are also recognized in other expense.

(o) Revenue Recognition
Oil and natural gas revenues are recorded using the sales method, whereby the Company recognizes oil and natural gas revenue based on the amount of oil and gas sold to purchasers. For the period ended December 31, 2005, 2004 and 2003, the Company did not have any oil or gas imbalances recorded. The Company does not recognize revenues until they are realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists; (ii) delivery has occurred or services have been rendered; (iii) the seller's price to the buyer is fixed or determinable; and, (iv) collectibility is reasonably assured.

The following summarizes revenue for each of the three years ended December 31 by product sold.

(in thousands)	**2005**	2004	2003
Oil revenue	**$ 47,800**	$ 28,455	$ 18,300
Effects of oil hedge	**(12,139)**	(7,458)	(1,659)
Gas revenue	**30,690**	15,735	18,121
Effects of natural gas hedge	**(201)**	(895)	(907)
	$ 66,150	$ 35,837	$ 33,855

(p) Recent Accounting Pronouncements
In December 2004, the Financial Accounting Standard Board ("FASB") issued SFAS No. 123(R), *"Share-Based Payment."* SFAS 123(R) will provide investors and other users of financial statements with more complete and neutral financial information by requiring that the compensation cost relating to share-based payment transactions be recognized in financial statements. That cost will be measured based on the fair value of the equity or liability instruments issued. SFAS 123(R) covers a wide range of share-based compensation arrangements, including share options, restricted share plans, performance-based awards, share appreciation rights, and employee share purchase plans. SFAS 123(R) replaces SFAS 123, *"Accounting for Stock-Based Compensation,"* and supersedes APB Opinion No. 25, *"Accounting for Stock Issued to Employees."*

SFAS 123, as originally issued in 1995, established as preferable a fair-value-based method of accounting for share-based payment transactions with employees. However, that Statement permitted entities the option of continuing to apply the guidance in APB Opinion No. 25, as long as the footnotes to financial statements disclosed what net income would have been had the preferable fair-value-based method been used. Public entities (other than those filing as small business issuers) were required to apply SFAS 123(R) as of the first interim or annual reporting period that begins after June 15, 2005. In April 2005, the Securities and Exchange Commission adopted a rule that amended the required application date of SFAS 123(R) from interim or annual reporting periods beginning after June 15, 2005, to the beginning of the entity's next fiscal year. The Company will be required to apply SFAS 123(R) effective January 1, 2006. The Company plans to use the modified prospective transition method, under which the Company will record as compensation expense over the requisite service period the fair value of all new options and previously granted options for which the requisite service had not been rendered as of January 1, 2006. The Company estimates that the adoption of SFAS 123(R), related to options outstanding as of December 31, 2005, will result in compensation expense of approximately $900,000, $600,000, $400,000, $200,000, $80,000 and $5,000 for 2006, 2007, 2008, 2009, 2010 and 2011, respectively, based on the Company's estimates of the fair value of those options.

In May 2005, the FASB issued SFAS No. 154, *"Accounting Changes and Error Corrections,"* a replacement of APB Opinion No. 20 and FASB SFAS No. 3, which changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS No. 154 applies to all voluntary changes in accounting principles and also to changes required by an accounting pronouncement that does not contain specific transition provisions. SFAS No. 154 carries forward without change the guidance contained in APB Opinion No. 20, *"Accounting Changes,"* for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The Company adopted SFAS No. 154, effective January 1, 2006, and the adoption could have a material impact on its financial position and results of operations if the Company has an accounting change.

(2) Fair Value of Financial Instruments

The carrying amount of cash, accounts receivable, accounts payable, and accrued liabilities approximates fair value because of the short maturity of these instruments.

The carrying amount of long-term debt approximates fair value because the Company's current borrowing rate is based on a variable market rate of interest. The Company also has derivative instruments which are described in Footnote 6.

(3) Oil and Gas Properties

The following table reflects capitalized costs related to the oil and gas properties as of December 31:

(in thousands)	2005	2004
Proved properties	$ 283,950	$ 219,719
Unproved properties, not subject to depletion	19,869	9,526
	303,819	229,245
Accumulated depletion	(89,202)	(77,623)
	$ 214,617	$ 151,622

The following table reflects, by category of cost, amounts excluded from the depletion base as of December 31, 2005:

Year Incurred	Leasehold Costs	Geological and Geophysical	Total
		(in thousands)	
2005	$ 11,374	$ 750	$ 12,124
2004	5,697	718	6,415
2003 and prior	944	386	1,330
	$ 18,015	$ 1,854	$ 19,869

At December 31, 2005 and 2004, unevaluated costs of approximately $19.9 million and $9.5 million were excluded from the depletion base. These costs consist primarily of acreage acquisition and related geological and geophysical costs. The majority of these costs relate to the Company's New Mexico and Utah leasehold positions which include federal leases with ten year terms. Although the Company expects transfers of costs to the full cost pool to commence in 2006 and continue throughout the term of the leases, timing is highly dependent on the Company's anticipated drilling program.

Certain directly identifiable internal costs of property acquisition, exploration, and development activities are capitalized. Such costs capitalized in 2005, 2004 and 2003 totaled approximately $1.5 million, $1.0 million and $900,000, respectively, including $180,000 of capitalized interest for the year ended December 31, 2005.

Depletion per equivalent unit of production (BOE) was $7.61, $7.05 and $6.83 for 2005, 2004, and 2003, respectively.

The following table reflects costs incurred in oil and gas property acquisition, exploration, and development activities for each of the years in the three year period ended December 31:

(in thousands)	**2005**	2004	2003
Proved property acquisition costs	**$ 23,763**	$ 39,763	$ 2,209
Unproved property acquisitions costs	**11,743**	7,400	3,831
Exploration	**15,455**	6,794	3,240
Development	**26,390**	13,954	5,650
	$ 77,351	$ 67,911	$ 14,930

In September and October 2004, in two separate transactions, Parallel purchased additional non-operated working interests in the Fullerton Field properties. The net purchase price for these two transactions was approximately $20.9 million.

In October and December 2004, Parallel purchased producing properties in the Carm-Ann San Andres and North Means Queen Unit located in Andrews and Gaines Counties, Texas. The combined net purchase price was approximately $16.5 million. In January 2005, Parallel acquired additional interest in these properties for a net purchase price of approximately $1.5 million. The 2005 purchase was made out of restricted cash.

In November 2005, Parallel purchased producing and undeveloped oil and gas properties in the Harris San Andres Field located in Andrews and Gaines Counties, Texas. The net purchase price was approximately $20.8 million. In January, 2006, Parallel acquired additional interest in these properties for a net purchase price of approximately $23.4 million, including adjustments. The 2006 purchase was made utilizing Parallel's restricted cash and revolving credit facility.

(4) Other Assets

Below are the components of other assets as of December 31, 2005 and 2004:

December 31, (in thousands)	**2005**	2004
Bank fees, net of accumulated amortization	**$ 1,675**	$ 702
Prepaid drilling[1]	**1,125**	—
Fair value of purchased oil and natural gas puts	**738**	—
Other	**12**	33
	$ 3,550	$ 735

(1) This represents the long-term portion of prepaid drilling costs to be transferred to property, plant and equipment as work is performed.

(5) Asset Retirement Obligation

On January 1, 2003, the Company adopted SFAS 143, *Accounting for Asset Retirement Obligations.* SFAS 143 requires companies to recognize a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and to capitalize an equal amount as part of the cost of the related oil and gas properties.

The adoption of SFAS 143 required the Company to record a non-cash expense, net of tax, of approximately $62,000 as a cumulative effect of change in accounting principle in the first quarter of 2003, as well as a non-current liability of approximately $1.5 million and an addition to oil and gas properties of approximately $1.5 million. The following table summarizes the Company's asset retirement obligation transactions.

(in thousands)	**2005**	2004	2003
Beginning asset retirement obligation	**$ 2,132**	$ 1,701	$ 1,469
Additions related to new properties	**367**	886	345
Deletions related to property disposals	**(116)**	(547)	(252)
Accretion expense	**112**	92	139
Ending asset retirement obligation	**$ 2,495**	$ 2,132	$ 1,701

On a pro forma basis, the 2003 net income amount as if the provisions of SFAS No. 143 had always been applied would have been approximately $7.7 million. Basic and diluted pro forma net income per share would have $.33 and $.31, respectively.

(6) Derivative Instruments

The Company enters into derivative contracts to provide a measure of stability in the cash flows associated with the Company's oil and gas production and interest rate payments and to manage exposure to commodity price and interest rate risk. The Company's objective is to lock in a range of oil and gas prices and to limit variability in its cash interest payments. In addition, the Company's revolving credit facility and second lien term loan facility require the Company to maintain derivative financial instruments which limit the Company's exposure to fluctuating commodity prices covering at least 50% of the Company's estimated monthly production of oil and natural gas extending 24 months into the future.

The Company designated all of its interest rate swaps, commodity collars and commodity swaps entered into in 2002 and 2003 as cash flow hedges ("hedges"). The effective portion of the unrealized gain or loss on cash flow hedges is recorded in other comprehensive income (loss) until the forecasted transaction occurs. During the term of a cash flow hedge, the effective portion of the change in the fair value of the derivatives is recorded in stockholders' equity as other comprehensive income (loss) and then transferred to oil and gas revenues when the production is sold and interest expense as the interest accrues. Ineffective portions of hedges (changes in fair value resulting from changes in realized prices that do not match the changes in the hedge or reference price) are recognized in other expense as they occur.

As of December 31, 2005 and 2004, the Company had recorded unrealized losses of $9.8 million and $11.3 million, respectively, related to its derivative instruments designated as hedges, which represented the estimated aggregate fair values of the Company's open hedge contracts as of that date. The unrealized losses are presented in stockholders' equity in the Consolidated Balance Sheets as accumulated other comprehensive loss of approximately $6.4 million, net of income taxes of approximately $3.3 million at December 31, 2005 and approximately $7.4 million, net of income taxes of approximately $3.8 million at December 31, 2004. During the twelve month period ending December 31, 2006, the Company expects all of the $6.4 million in accumulated comprehensive loss to be charged to earnings. In addition, the Company recorded unrealized losses related to the ineffective portion of derivative instruments accounted for as hedge contracts aggregating approximately $137,000 for the year ended December 31, 2005, and approximately $240,000 for the year ended December 31, 2004.

Derivative contracts not designated as hedges are "marked to market" at each period end and the increases or decreases in fair values recorded to earnings. No derivative instruments entered into subsequent to June 30, 2004 have been designated as cash flow hedges.

The Company is exposed to credit risk in the event of nonperformance by the counterparties to these contracts, BNP Paribas and Citibank, N.A. However, the Company periodically assesses their credit worthiness to mitigate this credit risk.

Interest Rate Sensitivity

Under the Company's revolving credit facility, the Company may elect an interest rate based upon the agent bank's base lending rate or the LIBOR rate, plus a margin ranging from 2.00% to 2.50% per annum, depending on the Company's borrowing base usage. The interest rate the Company is required to pay, including the applicable margin, may never be less than 5.00%. Under the Company's term loan facility second lien term loan facility, the Company may elect an interest rate based upon an alternate base rate, or the LIBOR rate, plus a margin of 4.50%.

Interest Rate Swaps. The Company has entered into interest rate swaps with BNP Paribas and Citibank, N.A. (the "counterparties") which are intended to have the effect of converting the variable rate interest payments to be made on the Company's revolving credit agreement and second lien term loan facility to fixed interest rates for the periods covered by the swaps. Under terms of these swap contracts, in periods during which the fixed interest rate stated in the agreement exceeds the variable rate (which is based on the 90 day LIBOR rate), the Company pays to the counterparties an amount determined by applying this excess fixed rate to the notional amount of the contract. In periods when the variable rate exceeds the fixed rate stated in the swap contracts, the counterparties pay an amount to the Company determined by applying the excess of the variable rate over the stated fixed rate to the notional amount of the contract.

As of December 31, 2005, we had employed a fixed interest rate swap contract with BNP Paribas, based on the 90-day LIBOR rates at the time of the contract. This interest rate swap is treated as a cash flow hedge as defined by SFAS 133. This interest rate swap is on $10 million of our variable rate debt for all of 2006. We will continue to pay the variable interest rates for this portion of our borrowing on the Revolving Credit Facility, but due to the interest rate swap, we have fixed the rate at 4.05%. As of December 31, 2005, the fair market value of this interest rate swap was $69,000.

As of December 31, 2005, we had also employed additional fixed interest rate swap contracts with BNP Paribas and Citibank, N.A. based on the 90-day LIBOR rates at the time of the contracts. However, these contracts are accounted for by "mark to market" accounting as prescribed in SFAS 133. Nonetheless, we view these contracts as additional protection against future interest rate volatility.

The table below recaps the nature of these interest rate swaps and the fair market value of these contracts as of December 31, 2005.

Period of Time	Notional Amounts	Weighted Average Fixed Interest Rates	Estimated Fair Market Value at December 31, 2005
	(dollars in millions)		*(dollars in thousands)*
January 1, 2006 thru December 31, 2006(1)	$ 10	4.05%	$ 69
January 1, 2006 thru December 31, 2006	$ 90	4.41%	299
January 1, 2007 thru December 31, 2007	$ 100	4.62%	118
January 1, 2008 thru December 31, 2008	$ 100	4.86%	(111)
January 1, 2009 thru December 31, 2009	$ 50	5.06%	(110)
January 1, 2010 thru October 31, 2010	$ 50	5.15%	(94)
Total Fair Market Value			$ 171

(1) Designated as a cash flow hedge.

Commodity Price Sensitivity

Except for the commodity swap noted in the table below, all of the commodity derivatives discussed below are accounted for by "mark to market" accounting as prescribed in SFAS 133.

Put Options. The Company purchased put options or "floors" on volumes of 3,000 MMBtu per day for a total of 642,000 MMBtu during the seven month period from April 1, 2006 through October 31, 2006 at an average floor price of $7.17 per MMBtu for a total consideration of approximately $230,000. The puts have a fair market value of $174,000 as of December 31, 2005.

Collars. Collars are contracts which combine both a put option or "floor" and a call option or "ceiling". These contracts may or may not involve payment or receipt of cash at inception, depending on "ceiling" and "floor" pricing.

A summary of the Company's collar positions at December 31, 2005 is as follows:

Period of Time	Barrels of Oil	NyMex Oil Prices Floor	NyMex Oil Prices Cap	MMBtu of Natural Gas	Houston Ship Channel Gas Prices Floor	Houston Ship Channel Gas Prices Cap	WAHA Gas Prices Floor	WAHA Gas Prices Cap	Fair Market Value
									(dollars in thousands)
January 1, 2006 thru December 31, 2006	289,800	$ 48.22	$ 75.83	—	$ —	$ —	$ —	$ —	$ (1,122)
April 1, 2006 thru October 31, 2006	—	$ —	$ —	428,000	$ 7.50	$ 13.90	$ —	$ —	52
April 1, 2006 thru October 31, 2006	—	$ —	$ —	214,000	$ —	$ —	$ 9.00	$ 14.55	181
January 1, 2007 thru December 31, 2007	219,000	$ 52.50	$ 83.00	—	$ —	$ —	$ —	$ —	230
April 1, 2007 thru October 31, 2007	—	$ —	$ —	214,000	$ 6.00	$ 11.05	$ —	$ —	(145)
January 1, 2008 thru December 31, 2008	109,800	$ 55.00	$ 76.50	—	$ —	$ —	$ —	$ —	153
January 1, 2009 thru December 31, 2009	91,250	$ 55.00	$ 73.00	—	$ —	$ —	$ —	$ —	126
January 1, 2010 thru December 31, 2010	76,000	$ 55.00	$ 71.00	—	$ —	$ —	$ —	$ —	113
Total Fair Market Value									$ (412)

Commodity Swaps. Generally, swaps are an agreement to buy or sell a specified commodity for delivery in the future, at an agreed fixed price. Swap transactions convert a floating or market price into a fixed price. For any particular swap transaction, the counterparty is required to make a payment to the Company if the reference price for any settlement period is less than the swap or fixed price for such contract, and the Company is required to make a payment to the counterparty if the reference price for any settlement period is greater than the swap or fixed price for such contract.

The Company has entered into oil and gas swap contracts with BNP Paribas. A recap for the period of time, number of barrels, and weighted average swap prices are as follows:

Period of Time	Barrels of Oil	Nymex Oil Swap Price	Fair Market Value
			(dollars in thousands)
January 1, 2006 thru December 20, 2006[1]	265,500	$ 23.04	$ (10,457)
January 1, 2006 thru December 31, 2006	182,500	$ 36.35	(4,806)
January 1, 2007 thru December 31, 2007	474,500	$ 34.36	(13,327)
January 1, 2008 thru December 31, 2008	439,200	$ 33.37	(11,741)
Total fair market value			$ (40,331)

(1) Designated as a cash flow hedge.

The Company has recognized a cumulative total of $625,000 in ineffectiveness on its one remaining commodity swap that it has designated as a cash flow hedge.

(7) Equity Investment and Property Acquisitions

Through 2005, the Company has invested approximately $3.4 million in three partnerships – Westfork Pipeline I, Westfork Pipeline II, and Westfork Pipeline V, to construct pipelines on its leaseholds in the Barnett Shale area. These investments are recorded as an equity investment in the accompanying consolidated balance sheet. The Company's ownership share of the partnerships is the same as its working interest in the leaseholds in the area. In 2005, transmission of natural gas commenced on Westfork Pipeline I. The partnerships are currently acquiring the necessary easements and permits for the Westfork Pipeline II and V.

As discussed in Note 3, the Company made several acquisitions of oil and natural gas properties during 2005 and 2004. The following table presents unaudited, pro forma operating results as if these property purchases had been made on January 1, 2005 and 2004. The pro forma results have been prepared for comparative purposes only. The pro formas are not intended to represent what actual results would have been if the acquisitions had been made on those dates and these pro forma amounts are not indicative of future results.

	2005			2004				
(in thousands, except per share data)	PLLL	Harris[1]	Total Pro Forma	PLLL	Fullerton	Carm Ann	Harris[1]	Total Pro Forma
				(restated)				
Oil and gas revenue	**$ 66,150**	**$ 6,817**	**$ 72,967**	$ 35,837	$ 3,484	$ 2,311	$ 6,063	$ 47,695
Operating income	**$ 33,345**	**$ 4,607**	**$ 37,952**	$ 12,266	$ 1,876	$ 587	$ 3,629	$ 18,358
Net income available to common stockholders	**$ (1,860)**	**$ 1,189**	**$ (671)**	$ 1,699	$ 785	$ (28)	$ 930	$ 3,386
Net income per common share:								
Basic	**$ (0.06)**	**$ 0.04**	**$ (0.02)**	$ 0.07	$ 0.03	$ —	$ 0.04	$ 0.14
Diluted	**$ (0.06)**	**$ 0.04**	**$ (0.02)**	$ 0.07	$ 0.02	$ —	$ 0.04	$ 0.13

(1) Does not include the Harris San Andres Field, Andrews and Gaines Counties, Texas purchased in January, 2006.

(8) Credit Facilities

The Company has two separate credit facilities. The Company's Third Amended and Restated Credit Agreement (or the "Revolving Credit Agreement"), dated as of December 23, 2005, with a group of bank lenders provides a revolving line of credit having a "borrowing base limitation" of $125.0 million at December 31, 2005. The total amount that the Company can borrow and have outstanding at any one time is limited to the lesser of $350.0 million or the borrowing base established by the lenders. At December 31, 2005, the principal amount outstanding under the Company's revolving credit facility was $50.0 million, and $490,000 was reserved for the Company's letters of credit. The second credit facility (or the "Second Lien Agreement") is a five year term loan facility provided to the Company under a Second Lien Term Loan Agreement, dated as of November 15, 2005, with a group of banks and other lenders. At December 31, 2005, the Company's term loan under the second lien agreement was fully funded in the principal amount of $50.0 million, which was outstanding on that same date.

The credit facilities have varying interest rates and consist of the following bank's base rate and LIBOR tranches at December 31:

(in thousands)	**2005**	2004
Revolving Facility note payable to banks,		
Agent bank's base lending rate of 7.25%	**$ —**	$ 5,000
Libor No.1 at 6.73% (resetting January 3, 2005)	**—**	55,000
Libor No.2 at 7.29% (resetting May 23, 2005)	**—**	19,000
Libor Tranche at 6.40% (resetting March 23, 2006)	**50,000**	—
Term Loan (Second Lien) payable to banks,		
Libor Tranche at 9.0% (resetting March 21, 2006)	**50,000**	—
Total notes payable to banks	**$ 100,000**	$ 79,000

Revolving Credit Facility

The Revolving Credit Agreement provides for a credit facility that allows the Company to borrow, repay and reborrow amounts available under the revolving credit facility. The amount of the borrowing base is based primarily upon the estimated value of the Company's oil and gas reserves. The borrowing base amount is redetermined by the lenders semi-annually on or about April 1 and October 1 of each year or at other times required by the lenders or at the Company's request. If, as a result of the lenders' redetermination of the borrowing base, the outstanding principal amount of the Company's loan exceeds the borrowing base, it must either provide additional collateral to the lenders or repay the principal of the revolving credit facility in an amount equal to the excess. Except for the principal payments that may be required because of the Company's outstanding loans being in excess of the borrowing base, interest only is payable monthly.

Loans made to the Company under this revolving credit facility bear interest at the bank's base rate or the LIBOR rate, at the Company's election. Generally, the bank's base rate is equal to the "prime rate" published in the Wall Street Journal. The LIBOR rate is generally equal to the sum of (a) the rate designated as "British Bankers Association Interest Settlement Rates" and offered on one, two, three, six or twelve month interest periods for deposits of $1.0 million, and (b) a margin ranging from 2.00% to 2.50%, depending upon the outstanding principal amount of the loans. If the principal amount outstanding is equal to or greater than 75% of the borrowing base, the margin is 2.50%. If the principal amount outstanding is equal to or greater than 50%, but less than 75% of the borrowing base, the margin is 2.25%. If the principal amount outstanding is less than 50% of the borrowing base, the margin is 2.00%.

The interest rate the Company is required to pay on its borrowings, including the applicable margin, may never be less than 5.00%. At December 31, 2005, the Company's Libor interest rate, plus margin, was 6.40% on $50.0 million.

In the case of base rate loans, interest is payable on the last day of each month. In the case of LIBOR loans, interest is payable on the last day of each applicable interest period.

If the total outstanding borrowings under the revolving credit facility are less than the borrowing base, an unused commitment fee is required to be paid to the lenders. The amount of the fee is .25% of the daily average of the unadvanced amount of the borrowing base. The fee is payable quarterly.

If the borrowing base is increased, the Company is required to pay a fee of .375% on the amount of any increase in the borrowing base.

All outstanding principal under the revolving credit facility is due and payable on October 31, 2010. The maturity date of the Company's outstanding loans may be accelerated by the lenders upon the occurrence of an event of default under the Revolving Credit Agreement.

The revolving credit agreement contains various restrictive financial covenants and compliance requirements. As a result of financial statement errors concerning the Company's accounting for certain oil and natural gas and interest rate derivative instruments, the Company was not in compliance with certain covenants concerning financial reporting. The Company has obtained waivers of these covenants from its lenders. The Company was in compliance with the remainder of the covenants to its revolving credit facility. See note 18. The revolving credit agreement also contains restrictions on all retained earnings and net income for payment of dividends on common stock.

Second Lien Term Loan Facility

The Second Lien Agreement provides a $50.0 million term loan to the Company. Loans made to the Company under this credit facility bear interest at an alternate base rate or the LIBOR rate, at the Company's election. The alternate base rate is the greater of (a) the prime rate in effect on such day and (b) the "Federal Funds Effective Rate" in effect on such day plus ½ of 1%, plus a margin of 3.50% per annum.

The LIBOR rate is generally equal to the sum of (a) the rate designated as "British Bankers Association Interest Settlement Rates" and offered on one, two, three or six month interest periods for deposits of $1.0 million and (b) an applicable margin rate per annum equal to 4.50%.

At December 31, 2005, the Company's Libor interest rate, plus margin, was 9.0% on $50.0 million.

In the case of alternate base rate loans, interest is payable the last day of each March, June, September and December. In the case of LIBOR loans, interest is payable the last day of the tranche period not to exceed a three month period.

All outstanding principal under the second lien agreement is due and payable on November 15, 2010. The maturity date may be accelerated by the lenders upon the occurrence of an event of default under the second lien agreement.

Prepayments in whole or in part if made prior to the first anniversary date will bear a premium of 1% of the amount prepaid; there is no premium after the first anniversary date.

The second lien agreement contains various restrictive financial covenants and compliance requirements. As a result of financial statement errors concerning the Company's accounting for certain oil and natural gas and interest rate derivative instruments, the Company was not in compliance with certain covenants concerning financial reporting. The Company has obtained waivers of these covenants from its lenders. The Company was in compliance with the remainder of the covenants to the second lien term loan facility. See note 18.

(9) Income Taxes

The Company's income tax provision is classified as follows:

Years ended December 31, (in thousands)	2005	2004	2003
		(restated)	
Income tax (benefit) expense, all deferred	**$ (1,676)**	$ 1,162	$ 3,031
Cumulative effect of change in accounting principle	**—**	—	(32)
Income tax (benefit) expense, deferred related to loss/gain on derivatives in other comprehensive loss	**515**	(1,917)	(1,916)
Total income tax provision (benefit)	**$ (1,161)**	$ (755)	$ 1,083

Income tax expense differs from the amount computed at the federal statutory rate as follows:

Years ended December 31, (in thousands)	2005	2004	2003
		(restated)	
Income tax (benefit) expense at statutory rate	**$ (1,110)**	$ 1,167	$ 3,700
Statutory depletion	**(443)**	(29)	(96)
State tax, net of federal benefit[1]	**16**	6	(594)
Nondeductible expenses and other	**(139)**	18	21
Income tax expense	**$ (1,676)**	$ 1,162	$ 3,031

(1) The state tax benefit in 2003 resulted from a reversal of a prior year estimate.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liability at December 31 are as follows:

(in thousands)	2005	2004
Current:		
Deferred tax assets:		
Fair market value losses on derivatives expected to be settled within one year	$ 5,241	$ 2,531
Noncurrent:		
Deferred tax assets:		
Net operating loss carryforwards, state and federal	$ 3,734	$ 4,196
Statutory depletion carryforwards	2,462	2,019
Alternative minimum tax credit carryforward	154	118
Fair market value losses on derivatives not expected to be settled within one year	9,331	3,417
Asset retirement obligations	149	110
Other	64	39
Total noncurrent deferred tax assets	15,894	9,899
Deferred tax liabilities:		
Property and equipment, principally due to differences in basis, expensing of intangible drilling costs for tax purposes and depletion	(23,930)	(16,386)
Total deferred tax liabilities	(23,930)	(16,386)
Net noncurrent deferred income tax liability	$ (8,036)	$ (6,487)

As of December 31, 2005, the Company had net operating loss carry forwards for regular tax and alternative minimum taxable income (AMT) purposes available to reduce future taxable income. These carry forwards expire as follows:

(in thousands)	Net Operating Loss	AMT Operating Loss
2019	$ 2,619	$ 3,019
2021	4,576	4,498
2022	44	44
2023	8	332
2024	3,718	3,806
	$ 10,965	$ 11,699

As of December 31, 2005, the Company had approximately $154,000 of AMT credit carryover that does not expire.

(10) Equity Transactions

Preferred Stock

On June 6, 2005, outstanding shares of the Company's 6% Convertible Preferred Stock, $0.10 par value per share were converted to common stock. Under terms of the Preferred Stock Agreement, all of the holders of the Convertible Preferred Stock elected to convert their shares into shares of the Company's common stock based on the original contractual conversion rate of $10.00 divided by $3.50. The holders of the Preferred Stock received approximately 2.8571 shares of common stock of the Company for each share of Preferred Stock.

Sale of Equity Securities

On February 9, 2005, the Company sold 5,750,000 shares of its common stock, $.01 par value per share, pursuant to a public offering at a price of $5.27 per share. Gross cash proceeds were $30.3 million, and net proceeds were approximately $27.7 million. The common shares were issued under Parallel's $100.0 million Universal Shelf Registration Statement on Form S-3 which became effective in November 2004. The proceeds were used to reduce the amount outstanding under the revolving credit facility.

(11) Stock Compensation, Warrants and Rights

The Company awards both incentive stock options and nonqualified stock options to selected key employees, officers, and directors. The options are awarded at an exercise price equal to the closing price of the Company's common stock on the date of grant. These options vest over a period of two to ten years with a ten-year exercise period. As of December 31, 2005, options expire beginning in 2006 and extending through 2015. Options to purchase a total of 17,500 shares of common stock remain available for grant.

A summary of the Company's employee stock options as of December 31, 2005, 2004 and 2003, and changes during the years ended on those dates is presented below:

	Year Ended December 31, 2005		Year Ended December 31, 2004		Year Ended December 31, 2003	
	Number of Shares	**Weighted Average Price**	Number of Shares	Weighted Average Price	Number of shares	Weighted Average Price
Stock options:						
Outstanding at beginning of year	**1,918,750**	**$ 3.71**	2,138,150	$ 3.65	2,338,750	$ 2.71
Options granted	**200,000**	**12.27**	—	—	180,000	2.96
Options exercised	**(714,000)**	**(3.15)**	(174,400)	(3.00)	(30,600)	(1.82)
Options cancelled	—	—	—	—	(100,000)	(4.97)
Options expired	—	—	(45,000)	(4.29)	(250,000)	(3.94)
Outstanding at end of year	**1,404,750**	**$ 5.22**	1,918,750	$ 3.71	2,138,150	$ 3.65
Exercisable at end of year	**1,159,750**	**$ 4.01**	1,776,250	$ 3.50	1,785,650	$ 3.85
Weighted average fair value of options granted during the year		**$ 8.71**		$ —		$ 1.64

	Average Remaining Life	Fair Market Value
		(in thousands)
Stock options outstanding as of 12/31/2005	6.2	$ 19,981
Currently exercisable as of 12/31/2005	5.0	$ 17,073

The following table summarizes information about the Company's employee stock options outstanding and exercisable at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number Outstanding at December 31, 2005	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2005	Weighted Average Exercise Price
$1.81 – $3.60	481,000	5 years	$ 2.92	481,000	$ 2.92
$4.09 – $5.50	723,750	5 years	$ 4.80	678,750	$ 4.79
$12.27	200,000	10 years	$ 12.27	—	$ —
	1,404,750			1,159,750	

(a) Stock Warrants

The Company has 300,030 warrants outstanding at December 31, 2005, 2004, and 2003, which were issued as part of the Company's initial public offering in 1980. Each warrant allows the holder to buy one share of common stock for $6.00. The warrants are exercisable for a 30 day period commencing on the date a registration statement covering exercise is declared effective. The warrants contain antidilution provisions and in the event of liquidation, dissolution, or winding up of the Company, the holders are not entitled to participate in the assets of the Company. The Company also has an additional 136,708 warrants outstanding at December 31, 2005, and 275,000 outstanding as of December 31, 2004 and 2003 issued as partial payment for services rendered for financial and investment advice in 2001. The warrants have an exercise price equal to the average of the last bid and asked price of the Company's common stock on the effective date of the issuance of the warrants and have a term of five years from date of issuance and a vesting period of one year. The warrants have an exercise price of $2.95 per share and contain a provision for cashless exercise. The expense related to these warrants in the amount of $99,000 was recorded in other expenses in 2001 and was based on the estimated fair value on the date of grant using the Black-Scholes option pricing model.

The Company has 100,000 warrants outstanding at December 31, 2005, 2004 and 2003, which were issued as partial payment for services rendered for financial and investment advice for the Company's private placement offering in December, 2003. The warrants have an exercise price equal to the average of the last bid and asked price of the Company's common stock on the effective date of the issuance of the warrants and have a term of five years from date of issuance and vesting period of one year. The warrants have an exercise price of $3.98 per share and contain a provision for cashless exercise. The fair value related to these warrants in the amount of $157,000 was recorded in other expenses in 2003 and was based on the estimated fair value on the date of grant using the Black-Scholes option pricing model.

(b) Stock Rights

On October 5, 2000, the board of directors declared a dividend of one Stock Right for each outstanding share of the Company's common stock. If a person acquires 15% or more of the Company's common stock or a tender offer or exchange offer is made for 15% or more of the common stock, each Stock Right will entitle the holder to purchase from the Company one one-thousandth of a share of Series A Preferred Stock, par value $0.10 per share, at an exercise price of $26.00 per one one-thousandth of a share, subject to adjustment.

Initially, the Stock Rights attach to all common stock certificates representing shares then outstanding, and no separate Stock Rights certificates will be distributed. The Stock Rights separate from the common stock upon the earlier of (1) ten business days following a public announcement that a person or group of affiliated or associated persons has acquired or obtained the right to acquire, beneficial ownership of 15% or more of the outstanding shares of common stock or (2) ten business days (or such later date as the board of directors shall determine) following the commencement of a tender or exchange offer that would result in a person or group beneficially owning 15% or more of such outstanding shares of common stock. The date the Stock Rights separate is referred to as the "distribution date".

Under certain circumstances the Stock Rights entitle the holders to buy the Company's stock at a 50% discount. In the event that (1) the Company is the surviving corporation in a merger or other business combination with an entity that owns 15% or more of the Company's outstanding stock; (2) any person shall acquire beneficial ownership of 15% of the Company's outstanding stock; or, (3) there is any type of recapitalization of the Company that results in an increase by more than 1% the proportionate share of equity securities of the Company owned by a person who owns 15% or more of the Company's outstanding stock, each Stock Right holder will have the option to buy for the purchase price common stock of the Company having a value equal to two times the purchase price of the Stock Right.

Under certain circumstances the Stock Rights entitle the holders to buy shares of the acquirer's common stock at a 50% discount. In the event that, at any time after a person has acquired 15% or more of the Company's common stock, (1) the Company enters into a merger or other business combination transaction in which the Company is not the surviving corporation; (2) the Company is the surviving corporation in a transaction in which all or part of the common stock is exchanged for cash, property or securities of any other person; or, (3) more than 50% of the assets, cash flow or earning power of the Company is sold, each right holder will have the option to buy for the purchase price stock of the acquiring company having a value equal to two times the purchase price of the Stock Right.

The Stock Rights are not exercisable until the distribution date and will expire at the close of business on October 5, 2010, unless earlier redeemed by the Company for $0.001 per Stock Right.

(c) Non-Employee Director Stock Grant Plan

Effective July 1, 2004, the Company began paying an annual retainer fee to each non-employee Director in the form of shares of the Company's common stock. Under the 2004 Non-Employee Director Stock Grant Plan, each non-employee Director is entitled to receive an annual retainer fee in the form of shares of common stock having a value of $25,000. The shares of stock are automatically granted on the first day of July in each year. The actual number of shares received is determined by dividing $25,000 by the average daily closing price of the common stock on the Nasdaq Stock Market for the ten consecutive trading days commencing fifteen trading days before the first day of July of each year. On July 1, 2005, and in accordance with the terms of the plan, the Company issued a total of 11,596 shares of common stock to four non-employee Directors as follows: Jeffrey G. Shrader – 2,899 shares; Dewayne E. Chitwood – 2,899 shares; Martin B. Oring – 2,899 shares; and Ray M. Poage – 2,899 shares. The Company has 83,510 remaining shares of common stock to issue to directors under this arrangement.

(12) Related Party Transactions

An entity owned by Thomas R. Cambridge, the Company's Chairman of the board of directors, is the owner and acted as the Company's agent in performing the routine day to day operations on two wells. In 2005, 2004 and 2003 the Company was billed approximately $20,000, $15,000 and $51,000, respectively, for the Company's pro rata share of lease operating and drilling expenses and received approximately $161,000, $165,000 and $198,000 in 2005, 2004, and 2003 respectively, in oil and gas revenues related to these wells. These two wells were acquired in 1984.

An entity, of which Mr. Cambridge is the President, owned interests in certain wells that are administered by the Company. During 2005 the Company charged approximately $2,000 for lease operating expenses and paid approximately $6,000 in oil and gas revenues related to these wells.

Dewayne E. Chitwood, a Director of the Company, also serves as director of an entity which owned 110,000 shares of preferred stock of the Company. In addition, a Foundation, where Mr. Chitwood is the Chairman of the board of directors of the Foundation; and a Trust where he is Trustee, owned a total of 55,000 shares each of preferred stock of the Company. These shares of preferred stock of the Company were purchased in 1998 at a price of $10 per share on the same terms as all other unaffiliated purchasers. On June 6, 2005 the 110,000 and the 55,000 shares of preferred stock were converted to 314,285 and 157,142 shares of common stock, respectively.

An entity, in which Mr. Chitwood is an officer of the managing general partner, owned interests in certain wells that are operated by the Company. During 2005, 2004 and 2003 the Company charged approximately $4,000, $14,000 and $23,000, respectively, for lease operating expenses and paid approximately $8,000, $48,000, and $74,000, respectively, in oil and gas revenues related to these wells. In 2005 the Company paid to the entity approximately $140,000 in payment of net proceeds attributable to its pro rata share from the sale in which it owed an interest.

In December, 2001, and prior to his employment with Parallel, Donald E. Tiffin, Parallel's Chief Operating Officer, received a 3% working interest from an unaffiliated third party in the Diamond M Project in Scurry County, Texas for services rendered in connection with assembling the project. In August, 2002, shortly after his employment with Parallel, and due to the personal financial exposure in the Diamond M Project and to prevent the interest from being acquired by a third party, Mr. Tiffin assigned two-thirds of his ownership interest in the project to Parallel at no cost, leaving him with a 1% working interest. Parallel acquired its initial interest in the Diamond M Project in December, 2001. During 2005, the Company charged approximately $81,000 for capital expenditures and lease operating expenses and paid approximately $55,000 in oil and gas revenues related to this project.

(13) Statements of Cash Flows

No Federal income taxes were paid in 2005, 2004 and 2003.

The Company made interest payments of approximately $5.4 million, $1.7 million, and $2.0 million in 2005, 2004 and 2003, respectively.

At December 31, 2005, 2004 and 2003, there were $2.5 million, $741,000 and $600,000, respectively, of property additions accrued in accounts payable.

(14) Major Customers

The following purchasers accounted for 10% or more of the Company's oil and gas sales for the years ended December 31:

	2005	2004	2003
Company A	14%	22%	30%
Company B	12%	—	—
Company C	40%	43%	33%

(15) Commitments and Contingencies

On December 30, 2005, the Company was named as a defendant in a lawsuit filed in the 352nd Judicial District Court of Tarrant County, Texas, Cause No. 352-215616-05, AFE Oil and Gas, L.L.C. (aka AFE Oil and Gas, LLC) v. Premium Resources II, L.P., Premium Resources, Inc., Danay Covert, Nick Morris, William D. Middleton, Dale Resources, L.L.C., and Parallel Petroleum, Inc.

In this suit, the plaintiff alleges breach of fiduciary duty, fraud and conspiracy to defraud, breach of contract, constructive trust, suit to remove cloud from title, declaratory judgment, alter ego, and statutory fraud and seeks recovery of an unspecified amount of actual damages, special damages, consequential damages, exemplary damages, attorneys' fees, pre-judgment and post-judgment interest and costs. Generally, the plaintiff alleges that it owns a 5.5% overriding royalty interest in certain oil and gas properties known as the "Square Top LP" and the "West Fork LP" leases located in Tarrant County, Texas. The plaintiff alleges that the defendants (other than Dale Resources and Parallel) wrongfully and intentionally allowed these original oil and gas leases to terminate, causing the termination of plaintiff's overriding royalty interest in each lease. The plaintiff further alleges that the defendants (other than Dale Resources and Parallel) failed to drill wells necessary to maintain the original leases in force and that after the original leases were allowed to terminate, the defendants (other than Dale Resources and Parallel) then acquired new oil and gas leases covering these same oil and gas properties, which were subsequently assigned to Dale Resources. Thereafter, Dale Resources allegedly assigned a portion of these new leases to Parallel.

In addition to seeking unspecified monetary damages, the plaintiff also seeks to impose a constructive trust for its benefit on the new oil and natural gas leases and seeks a judicial declaration that either (1) the plaintiff is the owner of an overriding royalty interest in the new leases or that (2) the original leases and plaintiff's interest in the original leases are still in effect. The plaintiff also claims that the new leases constitute a cloud on plaintiff's title and seeks to have that cloud removed. Based on Parallel's present understanding of this case, Parallel believes that it has substantial defenses to the plaintiff's claims and intends to vigorously assert these defenses. However, if the plaintiff is awarded an interest in the new leases, then Parallel could potentially become liable for the payment to plaintiff of the portion of production proceeds attributable to plaintiff's interest received by Parallel. On the other hand, if the plaintiff prevails on its claim that the original leases are still in effect, Parallel's interest in the new leases could become subject to forfeiture. Based on the information known to date, Parallel has not established a reserve for this matter.

The Company is currently a defendant in one other lawsuit. The Company does not believe the ultimate outcome of this lawsuit will have a material adverse effect on its financial condition or results of options. The is Company is not aware of any other threatened litigation and has not been a party to any bankruptcy, receivership, reorganization, adjustment or similar proceeding.

Prior to January 1, 2005, the Company had established a simplified employee pension plan ("SEP") covering all salaried employees of the Company. The employees could voluntarily contribute a portion of their eligible compensation, not to exceed $13,000, to the SEP. In addition to this annual salary deferral limit, employees who had reached the age of 50 or older during the calendar year could have elected to take advantage of a catch-up salary deferral contribution. Eligible participants could have increased their salary deferral by $3,000 for the year 2004. The Company made discretionary contributions to the SEP; however, total contributions could not exceed $41,000 per employee. During 2004 and 2003, the Company contributed an aggregate of approximately $133,000 and $106,000, respectively, to the SEP.

On January 1, 2005 the Company established a 401(k) Plan and Trust for eligible employees. Employees may not participate in the SEP with the establishment of the 401(k) Plan and Trust. During 2005, the Company contributed an aggregate of approximately $168,000 to the 401(k) Plan.

The Company leases office space under a non-cancelable operating lease expiring in 2010. Future annual payments under this operating lease are approximately $188,000, $199,000, $205,000, $210,000 and $35,000 for the years ending December 31, 2006 thru February 28, 2010, respectively. Rental expense under the Company's current and former lease totaled approximately $162,000, $127,000, and $130,000 for the years ended December 31, 2005, 2004 and 2003, respectively.

The Company leases two field offices and storage facilities. These two facilities are located in Andrews and Snyder, Texas. The Andrews office is under a non-cancelable commercial lease expiring in 2007 and the Snyder office ends upon the expiration or termination of a trade agreement with the prior operator. Future annual payments under these lease agreements total approximately $23,000 for 2006 and 2007 and $14,000 for 2008 thru 2010. Rental expense under these two leases totaled approximately $23,000, $15,000 and $2,400 for the year ended December 31, 2005, 2004 and 2003, respectively.

The Company has an Incentive and Retention Plan which provides for the payment to eligible officers and employees a one time performance bonus and retention payment upon the occurrence of a change of control as defined in the Plan. Because of the uncertainty of the occurrence of a change of control or corporate transaction within the meaning of the plan, the amount of these bonuses is undeterminable. Although the amount of the bonus is undeterminable at this time, if the Plan was calculated using the December 31, 2005, stock price of $17.01 per share, the Plan would have a balance of approximately $17.7 million.

In January 2006, the Company adopted a Non-officer Employee Severance Plan for the purpose of providing the Company's non-officer employees with an incentive to remain employed by with the Company. This Plan provides for a one-time severance payment to the non-officer employees equal to one year of their then "current base salary" upon the occurrence of a change of control within the meaning of the Plan. Based on the aggregate non-officer base salaries in effect as of December 31, 2005, the total severance amount payable under the plan would have been approximately $2.5 million.

(16) Supplemental Oil and Gas Reserve Data (Unaudited)

The Company has presented the reserve estimates utilizing an oil price of $56.09, $40.59 and $30.63 per Bbl and a gas price of $8.68, $5.65 and $5.45 per Mcf as of December 31, 2005, 2004 and 2003, respectively. Information for oil is presented in barrels (Bbl) and for gas in thousands of cubic feet (Mcf).

The estimates of the Company's proved natural gas reserves and related future net cash flows that are presented in the following tables are based upon estimates made by independent petroleum engineering consultants.

The Company's reserve information was prepared by independent petroleum engineering consultants as of December 31, 2005, 2004 and 2003. The Company cautions that there are many inherent uncertainties in estimating proved reserve quantities, projecting future production rates, and timing of development expenditures. Accordingly, these estimates are likely to change as future information becomes available. Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves expected to be recovered through existing wells, with existing equipment and operating methods.

A summary of changes in reserve balances is presented below:

	Total proved		Proved developed	
(in thousands)	BBL	MCF	BBL	MCF
Reserves as of December 31, 2002	10,271	15,633	8,263	11,202
Extensions and discoveries	1,412	1,811	283	1,811
Revisions of previous estimates	1,030	2,183	1,027	2,409
Production	(629)	(3,356)	(629)	(3,356)
Reserves as of December 31, 2003	12,084	16,271	8,944	12,066
Purchase of reserves in place	4,982	1,432	3,057	733
Sale of reserves in place	(18)	(467)	(18)	(468)
Extensions and discoveries	1,159	4,661	338	3,840
Revisions of previous estimates	1,438	(2,382)	1,618	(323)
Production	(729)	(2,690)	(729)	(2,690)
Reserves as of December 31, 2004	18,916	16,825	13,210	13,158
Purchase of reserves in place	2,299	456	619	122
Sale of reserves in place	(14)	(66)	(14)	(205)
Extensions and discoveries	944	13,106	69	8,502
Revisions of previous estimates	(30)	(1,492)	653	(739)
Production	(923)	(3,592)	(923)	(3,592)
Reserves as of December 31, 2005	**21,192**	**25,237**	**13,614**	**17,246**

The following is a standardized measure of the discounted net future cash flows and changes applicable to proved oil and gas reserves required by *Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities* (SFAS No. 69). The future cash flows are based on estimated oil and gas reserves utilizing prices and costs in effect as of year end, discounted at 10% per year and assuming continuation of existing economic conditions.

During 2005, the average sales price received by the Company for its oil was approximately $51.78 (unhedged) per Bbl, as compared to $39.05 in 2004; while the average sales price for the Company's gas was approximately $8.54 (unhedged) per Mcf in 2005, as compared to $5.85 per Mcf in 2004.

The standardized measure of discounted future net cash flows, in management's opinion, should be examined with caution. The basis for this table is the reserve studies prepared by independent petroleum engineering consultants, which contain imprecise estimates of quantities and rates of production of reserves. Revisions of previous year estimates can have a significant impact on these results. Also, exploration costs in one year may lead to significant discoveries in later years and may significantly change previous estimates of proved reserves and their valuation. Therefore, the standardized measure of discounted future net cash flow is not necessarily indicative of the fair value of the Company's proved oil and gas properties.

Future income tax expense was computed by applying statutory rates less the effects of tax credits for each period presented to the difference between pre-tax net cash flows relating to the Company's proved reserves and the tax basis of proved properties and available net operating loss and percentage depletion carryovers.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

December 31, (in thousands)	**2005**	2004	2003
Future cash inflows	**$ 1,407,153**	$ 862,945	$ 458,723
Future costs:			
Production	**(361,563)**	(260,312)	(149,548)
Development	**(36,335)**	(25,131)	(15,485)
Future income taxes	**(249,621)**	(137,765)	(66,757)
Future net cash flows	**759,634**	439,737	226,933
10% annual discount for estimated timing of cash flows	**(398,844)**	(233,328)	(110,667)
Standardized measure of discounted future net cash flows	**$ 360,790**	$ 206,409	$ 116,266

Changes in Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves

December 31, (in thousands)	**2005**	2004	2003
Increase (decrease):			
Purchases of minerals in place	**$ 29,354**	$47,727	$ —
Extensions and discoveries and improved recovery, net of future production and development costs	**40,702**	18,984	9,556
Accretion of discount	**26,625**	14,779	12,293
Net change in sales prices net of production costs	**135,242**	45,572	10,832
Changes in estimated future development costs	**(10,886)**	(8,641)	(6,948)
Revisions of quantity estimates	**(4,518)**	13,022	13,520
Net change in income taxes	**(52,181)**	(28,319)	(8,204)
Sales, net of production costs	**(47,974)**	(26,356)	(25,451)
Changes of production rates (timing)	**38,017**	13,375	11,052
Net increase	**154,381**	90,143	16,650
Standardized measure of discounted future net cash flows:			
Beginning of year	**206,409**	116,266	99,616
End of year	**$ 360,790**	$ 206,409	$ 116,266

(17) Selected Quarterly Financial Data (Unaudited)

(in thousands, except per share data)	Quarter First	Second	Third	Fourth
2005	*(restated)*	*(restated)*	*(restated)*	
Oil and gas revenues	$ 10,414	$ 12,263	$ 21,837	$ 21,636
Total costs and expenses	7,048	7,060	8,836	9,861
Operating income	3,366	5,203	13,001	11,775
Net income	$ (10,704)	$ (1,246)	$ 1,989	$ 8,372
Net income available to common stockholders	$ (10,847)	$ (1,374)	$ 1,989	$ 8,372
Net income (loss) per common share – basic	$ (0.38)	$ (0.04)	$ 0.06	$ 0.24
Net income (loss) per common share – diluted	$ (0.38)	$ (0.04)	$ 0.06	$ 0.24
2004			*(restated)*	*(restated)*
Oil and gas revenues	$ 8,001	$ 7,917	$ 7,745	$ 12,174
Total costs and expenses	5,306	5,675	5,774	6,816
Operating income	2,695	2,242	1,971	5,358
Net income (loss)	$ 1,482	$ 1,103	$ (1,868)	$ 1,554
Net income (loss) available to common stockholders	$ 1,339	$ 959	$ (2,010)	$ 1,411
Net income per share:				
Net income (loss) per common share – basic	$ 0.05	$ 0.04	$ (0.08)	$ 0.06
Net income (loss) per common share – diluted	$ 0.05	$ 0.04	$ (0.08)	$ 0.05

Detailed disclosures concerning restated quarterly financial statements are contained in Note 18.

(18) Restatement

This annual report on Form 10-K for the year ended December 31, 2005 includes detailed disclosures relative to the restatement of consolidated financial statements for the year 2004, the third and fourth fiscal quarters in 2004, and the first three fiscal quarters of 2005.

During the course of our preparation of the Company's December 31, 2005 10K, we identified errors with respect to the Company's use of hedge accounting for certain transactions under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (FAS 133). Specifically, the Company determined that its documentation of the relationship of hedged items and the derivative instruments being employed and designated as hedges was insufficient when compared to the documentation requirements in SFAS 133 for derivative instruments entered into during periods subsequent to June 30, 2004, and that accounting for derivative instruments entered into during periods subsequent to June 30, 2004 as cash flow hedges was, therefore, inappropriate.

Effects of the Restatement

The restatement also impacted or made changes to the following financial statement footnotes; Note 1, 6, 7, 9, 17 and added Note 18 Restatement.

The following tables set forth the effects of the restatement relating to the derivatives transactions on the affected line items within the Company's previously reported Consolidated Statements of Operations for the periods shown below:

As of December 31, 2004 (in thousands)	As Previously Reported	As Restated
Consolidated Balance Sheets data:		
Retained earnings	$ 22,073	$ 18,759
Accumulated other comprehensive loss, net of tax	(10,756)	(7,442)

December 31, 2004 (in thousands)	As Previously Reported	As Restated
Consolidated Statement of Operations data:		
Change in fair market value of derivative instruments	$ —	$ (5,726)
Gain (loss) on ineffective portion of hedges	(945)	(240)
Total other income (expense), net	(3,812)	(8,833)
Income before income taxes	8,454	3,433
Income tax benefit (expense), deferred	(2,869)	(1,162)
Income (loss) before cumulative effect of change in accounting principle	5,585	2,271
Net income	5,585	2,271
Net income available to common stockholders	5,013	1,699
Net income per common share:		
Basic	$ 0.20	$ 0.07
Diluted	$ 0.20	$ 0.07

Year Ended December 31, 2004 (in thousands)	As Previously Reported	As Restated
Consolidated Statement of Stockholders' Equity data:		
Decrease in value of cash flow hedges	$ (7,035)	$ (3,721)
Net income	5,585	2,271
Balance, December 31:		
Retained earnings	22,073	18,759
Accumulated other comprehensive loss	(10,756)	(7,442)

Consolidated Statement of Cash Flow:

Only certain individual line items within cash provided by operating activities have been restated in the statement of cash flows for 2004. Net cash flow from operating activities was not affected by the restatement.

The effect of the restatement on the quarterly financial statements by line item is as follows:

(in thousands) (unaudited)	As of March 31, 2005 As Previously Reported	As of March 31, 2005 As Restated	As of June 30, 2005 As Previously Reported	As of June 30, 2005 As Restated	As of September 30, 2005 As Previously Reported	As of September 30, 2005 As Restated
Condensed Consolidated Balance Sheet data:						
Other current assets	$ 104	$ 264	$ 225	$ 190	$ 437	$ 434
Total current assets	15,739	15,899	18,107	18,072	27,993	27,990
Other assets, net of accumulated amortization	687	829	612	774	828	575
Total assets	173,824	174,126	190,877	191,004	210,899	210,643
Derivative obligation – current	15,827	15,987	16,322	16,449	18,811	18,808
Total current liabilities	21,950	22,110	23,823	23,950	28,500	28,497
Derivative obligation – long term	24,107	24,249	27,209	27,209	31,861	31,608
Total long-term liabilities	77,848	77,990	93,107	93,107	106,248	105,995
Retained earnings	21,523	7,912	22,705	6,538	31,292	8,527
Accumulated other comprehensive loss	(24,067)	(10,599)	(25,626)	(9,459)	(32,229)	(9,464)
Total liabilities and stockholders' equity	$ 173,824	$ 174,126	$ 190,877	$ 191,004	$ 210,899	$ 210,643

(in thousands)	As of September 30, 2004 As Previously Reported	As of September 30, 2004 As Restated	As of December 31, 2004 As Previously Reported	As of December 31, 2004 As Restated
	(unaudited)			
Condensed Consolidated Balance Sheets data:				
Retained earnings	$ 20,263	$ 17,348	$ 22,073	$ 18,759
Accumulated other comprehensive loss	(13,187)	(10,272)	(10,756)	(7,442)

(in thousands) (unaudited)	Quarter Ended March 31, 2005 As Previously Reported	March 31, 2005 As Restated	June 30, 2005 As Previously Reported	June 30, 2005 As Restated	September 30, 2005 As Previously Reported	September 30, 2005 As Restated
Consolidated Statements of Operations data:						
Loss on hedging and derivatives	$ (3,212)	$ (2,555)	$ (3,645)	$ (2,741)	$ (5,565)	$ (3,664)
Total revenues	9,757	10,414	11,359	12,263	19,936	21,837
Operating income	2,649	3,366	4,241	5,203	11,039	13,001
Change in fair market value of derivatives	—	(17,633)	—	(6,065)	—	(9,388)
Gain (loss) on ineffective portion of hedges	(2,276)	(710)	(1,235)	(150)	2,864	404
Interest expense	(1,138)	(1,173)	(796)	(868)	(950)	(1,060)
Total other income (expense), net	(3,475)	(19,577)	(2,025)	(7,077)	1,944	(10,014)
Income (loss) before income taxes	(826)	(16,211)	2,216	(1,874)	12,983	2,987
Income tax benefit (expense), deferred	276	5,507	(763)	628	(4,396)	(998)
Net income (loss)	(550)	(10,704)	1,453	(1,246)	8,587	1,989
Net income (loss) available to common stockholders	(693)	(10,847)	1,325	(1,374)	8,587	1,989
Net income (loss) per common share:						
Basic	$ (0.02)	$ (0.38)	$ 0.04	$ (0.04)	$ 0.25	$ 0.06
Diluted	$ (0.02)	$ (0.38)	$ 0.04	$ (0.04)	$ 0.25	$ 0.06

(in thousands) (unaudited)	Quarter Ended September 30, 2004 As Previously Reported	September 30, 2004 As Restated	December 31, 2004 As Previously Reported	December 31, 2004 As Restated
Consolidated Statements of Operations data:				
Change in fair market value of derivative instruments	$ —	$ (4,417)	$ —	$ (1,309)
Gain (loss) on ineffective portion of hedges	57	57	(1,009)	(304)
Total other income (expense), net	(467)	(4,884)	(2,470)	(3,074)
Income (loss) before income taxes	1,504	(2,913)	2,888	2,284
Income tax benefit (expense), deferred	(457)	1,045	(935)	(730)
Net income (loss) before cumulative effect of change in accounting principle	1,047	(1,868)	1,953	1,554
Net income (loss)	1,047	(1,868)	1,953	1,554
Net income (loss) available to common stockholders	905	(2,010)	1,810	1,411
Net income (loss) per common share:				
Basic	$ 0.04	$ (0.08)	$ 0.07	$ 0.06
Diluted	$ 0.04	$ (0.08)	$ 0.07	$ 0.05

Consolidated Statement of Cash Flow:

Only certain individual line items within cash provided by operating activities have been restated in the statement of cash flow for 2004. Net cash flow from operating activities for this period was not affected by the restatement.

(in thousands) (unaudited)	Year-to-Date March 31, 2005 As Previously Reported	March 31, 2005 As Restated	June 30, 2005 As Previously Reported	June 30, 2005 As Restated	September 30, 2005 As Previously Reported	September 30, 2005 As Restated
Condensed Consolidated Statement of Cash Flows data:						
Net income (loss)	$ (550)	$ (10,704)	$ 903	$ (11,950)	$ 9,490	$ (9,961)
Deferred income tax expense (benefit)	(276)	(5,507)	487	(6,135)	4,883	(5,137)
Change in fair value of derivatives	—	16,951	—	22,126	—	29,662
Settlements on derivatives	—	682	—	1,570	—	3,424
Loss on ineffective portion of hedges	2,276	710	3,511	860	647	456
Other assets, net	48	48	123	123	(93)	186
(Increase) decrease in other current assets	75	75	(46)	(11)	(258)	61
Net cash provided by operating activities	3,775	4,457	9,811	11,416	19,112	23,134
Settlements on derivatives	—	(682)	—	(1,570)	—	(3,424)
Purchase of derivative instruments	—	—	—	(35)	—	(598)
Net cash used in investing activities	$ (4,398)	$ (5,080)	$ (21,686)	$ (23,291)	$ (34,680)	$ (38,702)

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PARALLEL PETROLEUM CORPORATION

March 16, 2006

By: /s/ Larry C. Oldham

Larry C. Oldham
President and Chief Executive Officer

March 16, 2006

By: /s/ Steven D. Foster

Steven D. Foster
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/s/ Thomas R. Cambridge Thomas R. Cambridge	Chairman of the Board of Directors	March 16, 2006
/s/ Larry C. Oldham Larry C. Oldham	President and Chief Executive Officer (Principal Executive Officer)	March 16, 2006
/s/ Steven D. Foster Steven D. Foster	Chief Financial Officer (Principal Financial and Accounting Officer)	March 16, 2006
/s/ Dewayne E. Chitwood Dewayne E. Chitwood	Director	March 16, 2006
/s/ Martin B. Oring Martin B. Oring	Director	March 16, 2006
/s/ Ray M. Poage Ray M. Poage	Director	March 16, 2006
/s/ Jeffrey G. Shrader Jeffrey G. Shrader	Director	March 16, 2006

Index to Exhibits

(a) Exhibits

No.	Description of Exhibit
3.1	Certificate of Incorporation of Registrant (Incorporated by reference to Exhibit 3.1 to Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2004)
3.2	Bylaws of Registrant (Incorporated by reference to Exhibit 3 of the Registrant's Form 8-K, dated October 9, 2000, as filed with the Securities and Exchange Commission on October 10, 2000)
3.3	Certificate of Formation of Parallel, L.L.C. (Incorporated by reference to Exhibit No. 3.3 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.4	Limited Liability Company Agreement of Parallel, L.L.C. (Incorporated by reference to Exhibit No. 3.4 of the Registrant's Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.5	Certificate of Limited Partnership of Parallel, L.P. (Incorporated by reference to Exhibit No. 3.5 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
3.6	Agreement of Limited Partnership of Parallel, L.P. (Incorporated by reference to Exhibit No. 3.6 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.1	Certificate of Designations, Preferences and Rights of Serial Preferred Stock – 6% Convertible Preferred Stock (Incorporated by reference to Exhibit 4.1 of Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2004)
4.2	Certificate of Designation, Preferences and Rights of Series A Preferred Stock (Incorporated by reference to Exhibit 4.2 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)
4.3	Rights Agreement, dated as of October 5, 2000, between the Registrant and Computershare Trust Company, Inc., as Rights Agent (Incorporated by reference to Exhibit 4.3 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)
4.4	Form of Indenture relating to senior debt securities of the Registrant (Incorporated by reference to Exhibit No. 4.4 of the Registrant's Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.5	Form of Indenture relating to subordinated debt securities of the Registrant (Incorporated by reference to Exhibit No. 4.5 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.6	Form of common stock certificate of the Registrant (Incorporated by reference to Exhibit No. 4.6 of the Registrant's Registration Statement on Form S-3, No. 333-119725 filed on October 13, 2004)
4.7	Warrant Purchase Agreement, dated November 20, 2001, between the Registrant and Stonington Corporation (Incorporated by reference to Exhibit 4.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
4.8	Warrant Purchase Agreement, dated December 23, 2003, between the Registrant and Stonington Corporation (Incorporated by reference to Exhibit 4.8 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
	Executive Compensation Plans and Arrangements (Exhibit No.'s 10.1 through 10.8):
10.1	1992 Stock Option Plan (Incorporated by reference to Exhibit 10.1 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)
10.2	Merrill Lynch, Pierce, Fenner & Smith Incorporated Prototype Simplified Employee Pension Plan (Incorporated by reference to Exhibit 10.6 of the Registrant's Form 10-K for the fiscal year ended December 31, 1995)
10.3	Non-Employee Directors Stock Option Plan (Incorporated by reference to Exhibit 10.3 of the Registrant's Form 10-Q of the Registrant for the fiscal quarter ended June 30, 2005)
10.4	1998 Stock Option Plan (Incorporated by reference to Exhibit 10.7 of Form 10-K of the Registrant for the fiscal year ended December 31, 1998)
10.5	Form of Incentive Award Agreements, dated December 12, 2001, between the Registrant and Thomas R. Cambridge, Larry C. Oldham, Eric A. Bayley and John S. Rutherford granting 2,394 Unit Equivalent Rights to Mr. Cambridge; 9,564 Unit Equivalent Rights to Mr. Oldham; 2,869 Unit Equivalent Rights to Mr. Bayley; and 7,173 Unit Equivalent Rights to Mr. Rutherford (Incorporated by reference to Exhibit 10.8 of Form 10-K of the Registrant for the fiscal year ended December 31, 2001)

10.6 2001 Non-Employee Directors Stock Option Plan (Incorporated by reference to Exhibit 10.7 of the Registrant's Form 10-Q Report for the fiscal quarter ended March 31, 2004)

10.7 2004 Non-Employee Director Stock Grant Plan (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated September 22, 2004)

10.8 Incentive and Retention Plan (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated September 23, 2004 and filed with the Securities and Exchange Commission on September 29, 2004)

10.9 Certificate of Formation of First Permian, L.L.C. (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated June 30, 1999)

10.10 Limited Liability Company Agreement of First Permian, L.L.C. (Incorporated by reference to Exhibit 10.2 of the Registrant's Form 8-K Report dated June 30, 1999)

10.11 Amended and Restated Limited Liability Company Agreement of First Permian, L.L.C. dated as of May 31, 2000 (Incorporated by reference to Exhibit 10.16 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)

10.12 Credit Agreement, dated June 30, 1999, by and among First Permian, L.L.C., Parallel Petroleum Corporation, Baytech, Inc., and Bank One, Texas, N.A. (Incorporated by reference to Exhibit 10.6 of the Registrant's Form 8-K Report dated June 30, 1999)

10.13 Limited Guaranty, dated June 30, 1999, by and among First Permian, L.L.C., Parallel Petroleum Corporation and Bank One, Texas, N.A. (Incorporated by reference to Exhibit 10.7 of the Registrant's Form 8-K Report dated June 30, 1999)

10.14 Second Restated Credit Agreement, dated October 25, 2000, among First Permian, L.L.C., Bank One, Texas, N.A., and Bank One Capital Markets, Inc. (Incorporated by reference to Exhibit 10.22 of Form 10-K of the Registrant for the fiscal year ended December 31, 2000)

10.15 Loan Agreement, dated as of January 25, 2002, between the Registrant and First American Bank, SSB (Incorporated by reference to Exhibit 10.25 of Form 10-K of the Registrant for the fiscal year ended December 31, 2001)

10.16 Purchase and Sale Agreement, dated as of November 27, 2002, among JMC Exploration, Inc., Arkoma Star L.L.C., Parallel, L.P. and Texland Petroleum, Inc. (Incorporated by reference to Exhibit 10.1 of Form 8-K of the Registrant, dated December 20, 2002)

10.17 First Amended and Restated Credit Agreement, dated December 20, 2002, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, Western National Bank and BNP Paribas (Incorporated by reference to Exhibit 10.2 of Form 8-K of the Registrant, dated December 20, 2002)

10.18 Guaranty dated December 20, 2002, between Parallel, L.L.C. and First American Bank, SSB, as Agent (Incorporated by reference to Exhibit 10.3 of Form 8-K of the Registrant, dated December 20, 2002)

10.19 First Amendment to First Amended and Restated Credit Agreement, dated as of September 12, 2003, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, Western National Bank, and BNP Paribas (Incorporated by reference to Exhibit 10.29 of Form 10-Q of the Registrant for the quarter ended September 30, 2003)

10.20 Second Amendment and Restated Credit Agreement, dated September 27, 2004, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, BNP Paribas, Citibank, F.S.B. and Western National Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated September 27, 2004 and filed with the Securities and Exchange Commission on October 1, 2004)

10.21 Agreement of Limited Partnership of West Fork Pipeline Company LP (Incorporated by reference to Exhibit 10.21 of Form 10-K of the Registrant for the fiscal year ended December 31, 2004)

10.22 First Amendment to Second Amended and Restated Credit Agreement, dated as of December 27, 2004, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, BNP Paribas, Citibank, F.S.B. and Western National Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated December 30, 2004 and filed with the Securities and Exchange Commission on December 30, 2004)

10.23 Second Amendment to Second Amended and Restated Credit Agreement, dated as of April 1, 2005, by and among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C., First American Bank, SSB, BNP Paribas, Citibank, F.S.B. and Western National Bank (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated April 4, 2005 and filed with the Securities and Exchange Commission on April 8, 2005)

10.24 Third Amendment to Second Amended and Restated Credit Agreement (Incorporated by reference to Exhibit 10.1 of the Registrant's Form 8-K Report dated October 4, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.25 Purchase and Sale Agreement, dated as of October 14, 1005, among Parallel, L.P., Lynx Production Company, Inc., Elton Resources, Inc., Cascade Energy Corporation, Chelsea Energy, Inc., William P. Sutter, Trustee, William P. Sutter Trust, J. Leroy Bell, E. L. Brahaney, Brent Beck, Cavic Interests, LLC and Stanley Talbott (Incorporated by reference to Exhibit 10.2 of the Registrant's Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.26 Ancillary Agreement to Purchase and Sale Agreement, dated October 14, 2005, between Parallel, L.P. and Lynx Production Company, Inc. (Incorporated by reference to Exhibit 10.3 of the Registrant's Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.27 Guarantee of Parallel, L.P., dated October 13, 2004 (Incorporated by reference to Exhibit 10.4 of the Registrant's Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.28 ISDA Master Agreement, dated as of October 13, 2005, between Parallel, L.P. and Citibank, N.A. (Incorporated by reference to Exhibit 10.5 of the Registrant's Form 8-K Report dated October 14, 2005 and filed with the Securities and Exchange Commission on October 20, 2005)

10.29 Third Amended and Restated Credit Agreement, dated as of December 23, 2005, among Parallel Petroleum Corporation, Parallel, L.P., Parallel, L.L.C. and Citibank Texas, N.A., BNP Paribas, CitiBank F.S.B., Western National Bank, Compass Bank, Comerica Bank, Bank of Scotland and Fortis Capital Corp. (Incorporated by reference to Exhibit No. 10.1 of the Registrant's Form 8-K Report, dated December 23, 2005, as filed with the Securities and Exchange Commission on December 30, 2005)

10.30 Second Lien Term Loan Agreement, dated November 15, 2005, among Parallel Petroleum Corporation, Parallel, L.P., BNP Paribas and Citibank Texas, N.A. (Incorporated by reference to Exhibit No. 10.4 of the Registrant's Form 8-K Report, dated November 15, 2005, as filed with the Securities and Exchange Commission on November 21, 2005)

10.31 Intercreditor and Subordination Agreement, dated November 15, 2005, among Citibank Texas, N.A., BNP Paribas, Parallel Petroleum Corporation, Parallel, L.P. and Parallel, L.L.C. (Incorporated by reference to Exhibit No. 10.5 of the Registrant's Form 8-K Report, dated November 15, 2005, as filed with the Securities and Exchange Commission on November 21, 2005)

14 Code of Ethics (Incorporated by reference to Exhibit No. 14 of the Registrant's Form 10-K Report for the fiscal year ended December 31, 2003 and filed with the Securities and Exchange Commission on March 22, 2004)

21 Subsidiaries (Incorporated by reference to Exhibit No. 21 of the Registrant's Form 10-K Report for the fiscal year ended December 31, 2003 and filed with the Securities and Exchange Commission on March 22, 2004)

*23.1 Consent of BDO Seidman, LLP

*23.2 Consent of Cawley Gillespie & Associates, Inc. Independent Petroleum Engineers

*31.1 Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*31.2 Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*32.1 Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*32.2 Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Filed herewith.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

Parallel Petroleum Corporation
Midland, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 33-90296 and No. 333-112518) and Form S-8 (No. 33-57348, No. 333-34617 and No. 333-669380) of Parallel Petroleum Corporation of our reports dated March 10, 2006, relating to the consolidated financial statements and the effectiveness of Parallel Petroleum Corporation's internal control over financial reporting, which appear in this Annual Report on Form 10-K. Our report on the effectiveness of internal control over financial reporting expresses an adverse opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2005.

/s/ BDO Seidman, LLP
Houston, Texas
March 16, 2006

Exhibit 23.2

Consent of Cawley, Gillespie & Associates, Inc.

As independent petroleum engineers, we hereby consent to the incorporation by reference in the registration statements (No. 33-57348, No. 333-34617, No. 333-66938 and No. 333-117533) on Forms S-8, and the registration statements (No. 33-90296, No. 333-112518 and No. 333-119725) on Forms S-3 of Parallel Petroleum Corporation of information from our reserves report dated January 16, 2006 and all references to our firm included in or made a part of the annual report on Form 10-K of Parallel Petroleum Corporation for the fiscal year ended December 31, 2005.

/s/ Cawley, Gillespie & Associates, Inc.
Ft. Worth, Texas
March 16, 2006

Exhibit 31.1

Certifications

I, Larry C. Oldham, certify that:

1. I have reviewed this annual report on Form 10-K of Parallel Petroleum Corporation.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report.

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: March 16, 2006

By: /s/ Larry C. Oldham

Larry C. Oldham
President and Chief Executive Officer
(principal executive officer)

Exhibit 31.2

Certifications

I, Steven D. Foster, certify that:

1. I have reviewed this annual report on Form 10-K of Parallel Petroleum Corporation.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report.

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: March 16, 2006

By: /s/ Steven D. Foster

Steven D. Foster
Chief Financial Officer
(principal financial officer)

Exhibit 32.1

Certification

(Not filed pursuant to the Securities Exchange Act of 1934)

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Larry C. Oldham, the President and Chief Executive Officer of Parallel Petroleum Corporation ("Parallel"), hereby certifies that the Annual Report on Form 10-K of Parallel for the year ended December 31, 2005 fully complies with the periodic reporting requirements of the Securities Exchange Act of 1934, as amended, and the information contained in that Form 10-K Report fairly presents, in all material respects, the financial condition and results of operations of Parallel.

Dated: March 16, 2006

/s/ Larry C. Oldham

Larry C. Oldham
President and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Parallel Petroleum Corporation and will be retained by Parallel Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certification

(Not filed pursuant to the Securities Exchange Act of 1934)

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, the undersigned, Steven D. Foster, the Chief Financial Officer of Parallel Petroleum Corporation ("Parallel"), hereby certifies that the Annual Report on Form 10-K of Parallel for the year ended December 31, 2005 fully complies with the periodic reporting requirements of the Securities Exchange Act of 1934, as amended, and the information contained in that Form 10-K Report fairly presents, in all material respects, the financial condition and results of operations of Parallel.

Dated: March 16, 2006

/s/ Steven D. Foster

Steven D. Foster
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Parallel Petroleum Corporation and will be retained by Parallel Petroleum Corporation and furnished to the Securities and Exchange Commission or its staff upon request.

Corporate Information

Annual Meeting

Our annual stockholders' meeting will be held at 10:00 a.m. Central time, on Wednesday, June 21, 2006, at The Petroleum Club of Midland, 501 West Wall Street, Midland, Texas.

Form 10-K and Interactive Annual Report

A copy of Parallel's Form 10-K and other publications, including an interactive version of this Annual Report, are available at our Web site, http://www.plll.com.

Additional Information

If you would like additional information regarding the Company or to be added to our email, fax or mailing lists, please contact:

Cindy Thomason
Manager of Investor Relations
(432) 684-3727, ext. 3027
Email: cindyt@plll.com

Stock Transfer Agent

Communications concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to the transfer agent.

Computershare Trust Company
350 Indiana Street, Suite 800
Golden, Colorado 80401
(303) 262-0600 or (800) 962-4284

Stock Price Data (closing sales prices)

		High	Low
2004	First Quarter	$ 4.67	$ 3.60
	Second Quarter	$ 5.35	$ 3.83
	Third Quarter	$ 5.68	$ 4.38
	Fourth Quarter	$ 5.60	$ 4.83
2005	**First Quarter**	**$ 6.30**	**$ 6.02**
	Second Quarter	**$ 7.87**	**$ 7.52**
	Third Quarter	**$ 11.75**	**$ 11.24**
	Fourth Quarter	**$ 15.29**	**$ 14.60**

Corporate Headquarters

1004 N. Big Spring Street, Suite 400
Midland, Texas 79701
Telephone: (432) 684-3727
Facsimile: (432) 684-3905
Email: parallel@plll.com
Web site: http://www.plll.com

Legal Counsel

Lynch, Chappell & Alsup
Midland, Texas

Independent Auditors

BDO Seidman, LLP
Houston, Texas

Officers and Directors

See page 28 of the narrative section of this Annual Report.

Common Stock

Parallel Petroleum's common stock is traded on the NASDAQ National Market System (symbol: PLLL). As of March 14, 2006, there were approximately 1,431 stockholders of record.

We have not paid, and do not intend to pay in the foreseeable future, cash dividends on our common stock. The revolving credit facility and second lien term loan facility we have with our lenders prohibit the payment of dividends on the common stock. See "Risks Related to Our Business – We do not pay dividends on our common stock" on page 28 of the Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operation – Capital Resources and Liquidity" on page 46 of the Form 10-K section of this Annual Report.

PARALLEL
PETROLEUM CORPORATION

1004 N. Big Spring Street, Suite 400
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NASDAQ: PLLL
http://www.plll.com